Version

1.0

SCHLUMBERGER

Microhole Coiled Tubing Drilling

Operational Study

DOE MICROHOLE COILED TUBING DRILLING

Operational Study

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Chapter

1

Coiled tubing size selection

This chapter examines the primary factors used to determine the selection of proper coiled tubing size.

The DOE microhole coiled tubing drilling project aims to reduce the cost of drilling and completing a well by using coiled tubing to drill a microhole. Past experience has shown that a sufficient level of activity must be sustained to keep the unit operating if the cost of drilling a well with coiled tubing is to be reduced. The development of microhole completions is relatively recent and the supplier base and available tools are limited. For the purposes of this study, therefore, rather than designing a unit exclusively for the microhole completion market, a maximum completion size has been determined that will maximize the unit's potential by enabling it to be used by a greater portion of the drilling market.

Based on research into current shallow well drilling areas and the types of completions involved, a theoretically ideal wellbore schematic has been developed with a maximum total measured depth (TMD) of 6,000 ft and a final completion size no greater than 4-1/2 in., bearing in mind that a surface and intermediate string might also be needed to isolate different hole conditions.

The conductor will be rotary-drilled in all completions, requiring the use of a device to rotate the drill pipe or auger. Chapter 10 of this study discusses various rotary devices.

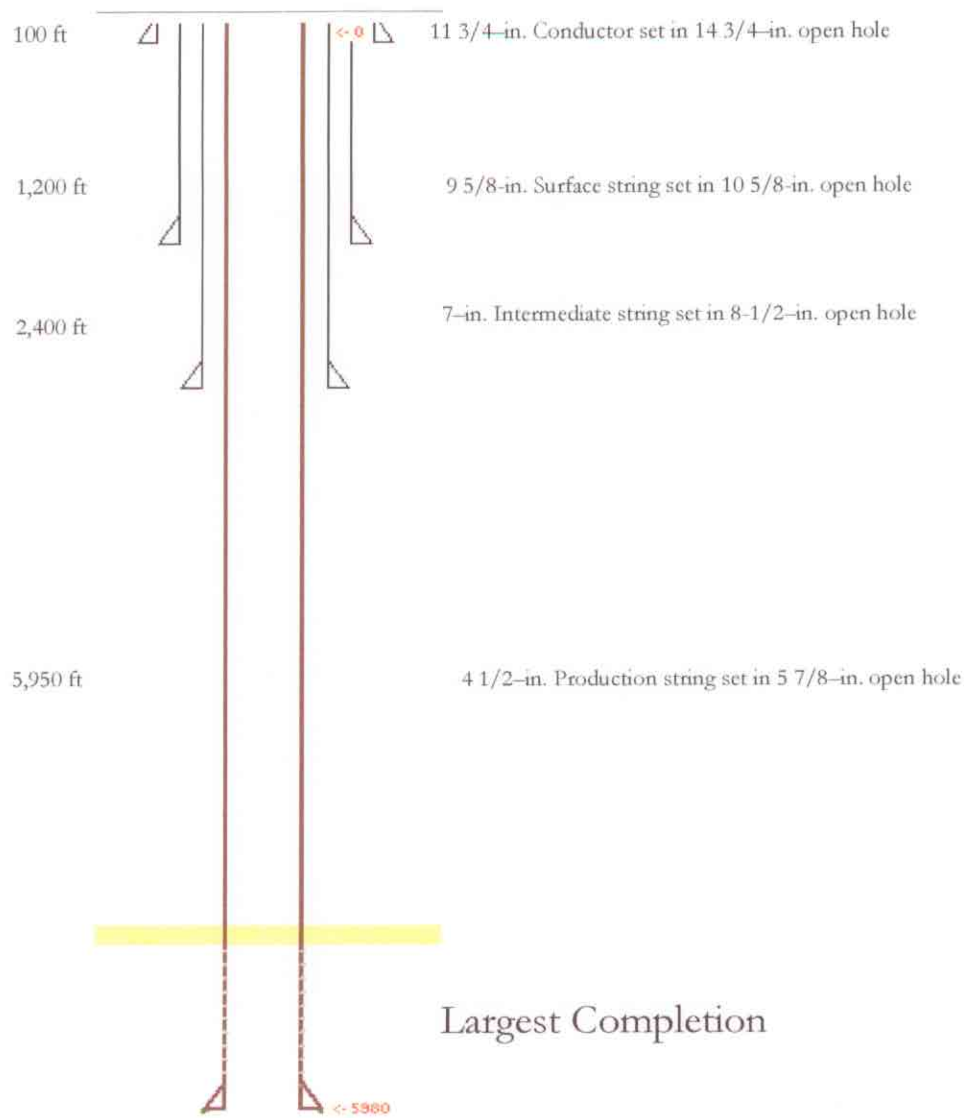

Figure 1

The wellbore schematic (fig 1) is referenced in the following sections, and serves as the worst-case scenario with regards to the largest envisioned completion for the purposes of this study. Horizontal sections in the wellbore will not exceed 1000 ft; and a 5 7/8-in. open hole will be the largest diameter for any horizontal section. Smaller completion sizes will not be included in this project, as they historically take lower flow rates and smaller motor sizes to drill.

The project objective is to construct a highly mobile, lightweight and cost-effective coiled tubing drilling unit. To keep this unit small and lightweight, the minimum coiled tubing pipe sizes that can be run must be understood. Pipe sizes studied in this project will be 1-3/4 in., 2 in., 2-3/8 in., 2-5/8 in. and 2-7/8 in.

Coiled tubing fatigue modeling will be used to determine the number of cycles over the goose neck can be made by a particular coiled tubing size under a given circulating pressure. As circulating pressure is increased within a coiled tubing string, the string's effective cycle life is reduced. Smaller coiled tubing sizes have higher cycle lives than larger coiled tubing sizes, but require a higher pump pressure to achieve equal fluid rates. The fluid rate is important when examining hole cleaning and downhole motor operation.

The following chart shows when 80 percent fatigue life, based on crack initiation models, has been reached. Increasing wall thickness increases usable cycle life; therefore, all coiled tubing wall thicknesses were modeled using the maximum wall thickness available for all sizes. Coiled tubing design aid software was used to generate (Table 1).

80 Percent Fatigue Life Per Cycle

Reel Diameter	CT Size	Wall Thickness In inches	1000 psi	2000 psi	3000 psi	4000 psi	5000 psi	6000 psi	7000 psi
70"	1.75"	.204	162	158	138	111	86	65	49
80"	2.0"	.204	152	141	114	86	62	45	32
95"	2.375"	.204	135	116	84	57	38	26	17
105"	2.625"	.204	119	95	64	40	25	16	10
115"	2.875"	.204	113	86	55	33	20	12	8

Indicates undesirable pressure due to reduced cycle life.

(Table 1)

Effect of reel diameter on fatigue life. By increasing the reel core diameter, we can also increase the expected fatigue life. The reel core diameter is limited because of travel restrictions and to increase reel capacity. The following graph illustrates how increasing the reel core diameter increases the cycle life of the various strings. For this model the minimum reel diameter for 2 7/8–in. pipe is used in order to maintain the smallest reel core diameter and thereby maximize reel capacity (Table 2).

80 Percent Fatigue Life Per Cycle

Reel Diameter	CT Size	Wall Thickness In inches	1000 psi	2000 psi	3000 psi	4000 psi	5000 psi	6000 psi	7000 psi
115"	1.75"	.204	388	368	295	222	164	121	91
115"	2.0"	.204	270	244	186	134	95	68	50
115"	2.375"	.204	176	148	105	70	47	32	22
115"	2.625"	.204	133	105	70	44	28	18	12
115"	2.875"	.204	113	86	55	33	20	12	8

Indicates undesirable pressure due to reduced cycle life.

(Table 2)

To view the way in which reel diameter affects maximum pump pressure, table 3 displays the maximum obtainable pump pressure while maintaining relatively equivalent fatigue lives between strings.

Reel Diameter	CT Size	Pump Pressure	Reel Diameter	CT Size	Pump Pressure
70"	1.75"	5000 psi	115"	1.75"	7000 psi
80"	2.0"	4000 psi	115"	2.0"	5500 psi
95"	2.375"	3000 psi	115"	2.375"	3500 psi
105"	2.625"	2250 psi	115"	2.625"	2500 psi
115"	2.875"	2000 psi	115"	2.875"	2000 psi

(Table 3)

This table 3 shows that we can expect equal fatigue life out of each string based on associated pump pressures. These pump pressures provide a guideline for the maximum flow rate achievable through the coiled tubing string. This flow rate directly affects motor performance and cleanout efficiency.

By performing iterations in the wellbore simulator model, pump pressures and fill removal efficiency versus flow rate can be determined. The wellbore simulator is run for each completion size of the wellbore schematic. The results are shown in the following tables 4,5 & 6.

Pump Pressure at Different Flow Rates Based on 12.5 ppg Brine and 380 psi Pressure Drop Across Motor

Surface Casing

Pump Rate bpm	2.0" CT	2.375" CT	2.625" CT	2.875" CT	Percent of total fill removed
	Surface Pump Pressure psi				
3	4,696	1,667	951	861	98%
4	7,883	2,748	1,524	915	98.9%
5	- - - - -	4,107	2,254	1,328	99%
6	- - - - -	5,729	3,132	1,829	99%
7	- - - - -	- - - - -	- - - - -	2,417	99%
8	- - - - -	- - - - -	- - - - -	- - - - -	99%
9	- - - - -	- - - - -	- - - - -	- - - - -	99%

Table 4

Intermediate Casing

Pump Rate bpm	2.0" CT	2.375" CT	2.625" CT	2.875" CT	Percent of total fill removed
	Surface Pump Pressure psi				
2.5	3,464	1,299	791	540	99.9%
2.75	4,081	1,500	893	593	100%
3	4,750	1,660	1,006	653	100%
4	- - - - -	2,792	1,568	960	100%

Table 5

Production Casing

Pump Rate bpm	1.75" CT	2.0" CT	2.375" CT	2.625" CT	2.875" CT
	Surface Pump Pressure psi				
2.25	6,600	2,945	1,186	775	580
2.5	- - - - -	3,522	1,365	863	620
2.75	- - - - -	4,137	1,564	963	671
3.0	- - - - -	4,800	1,784	1,076	731
3.25	- - - - -	5,524	2,023	1,200	797
3.5	- - - - -	- - - - -	2,282	1,335	871
3.75	- - - - -	- - - - -	2,559	1,481	952
4.0	- - - - -	- - - - -	2,853	1,637	1,039
4.5	- - - - -	- - - - -	3,496	1,980	1,231
5.0	- - - - -	- - - - -	4,207	2,363	1,448
5.5	- - - - -	- - - - -	- - - - -	2,783	1,687
6.0	- - - - -	- - - - -	- - - - -	3,240	1,949
6.5	- - - - -	- - - - -	- - - - -	- - - - -	2,233
7.0	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -

Note: Production casing is a 1,000 ft horizontal section at 5,000 ft

Table 6

The previous tables indicate the surface pump pressure required to achieve given rates through the given size of coiled tubing. For all iterations the length of the string remained constant at 7,000 ft.

Actual pressures may very depending on the characteristics of the fluid pumped and the rate of penetration while drilling. Therefore, it is important to not work at the extremes of a pressure group when using these tables. It is advisable to allow for a minimum of 10 percent error on all the simulated pressures.

Data not reported in the tables indicates a pressure that exceeds the maximum allowable pressure based on the previous fatigue life model. All the data displayed indicates a usable flow rate based on the fatigue life model.

Next, the minimum flow rate needed to operate the proper downhole motor for the size of hole drilled must be considered. The table 7 provides estimates of the flow rate requirements based on various downhole motors. The specific motor specifications will vary depending on the type of motor being used.

Motor Size	Minimum Flow Rate bpm	Maximum Flow Rate bpm	Maximum Recommended Hole Size
2-1/16"	0.5	1.2	3-1/2"
2-3/8"	0.5	1.5	4-1/2"
2-7/8"	0.5	2.6	4-1/2"
3-3/4"	0.7	4.8	5-7/8"
4-3/4"	2.3	7.0	7-7/8"
5.0"	2.3	8.3	7-7/8"
5.5"	2.3	8.3	8-3/4"
6-1/2"	4.7	14.3	9-7/8"

Source: Black Max *Operators Manual*

Table7

This table 7 shows that the minimum allowable flow rate is 4.7 bpm to drill a surface string with a 6 1/2–in. motor. Referring back to the pressure tables shows that coiled tubing from 2.375-in. to 2.875 in. will provide a sufficient flow rate to meet the minimum flow requirements.

The last factor in determining the optimum coiled tubing size is the cost of the string compared to its expected life. Table 8 lists representative numbers for the cost of a coiled tubing string. It is important to note that these numbers can change with the cost of steel and do not include shipping and handling.

SIZE & GAUGE	WEIGHT LB/FT	80 Yield	Cost/7000ft
1.75" + 0.204"	3.377	$4.59	$32,130.00
2.00" + 0.204"	3.923	$5.22	$36,540.00
2.375" + 0.204"	4.742	$5.83	$40,810.00
2.625" + 0.204"	5.288	$6.50	$45,500.00
2.875" + 0.204"	5.834	$7.29	$51,030.00

Source: Precision Tube Technology Price List

Table 8

By using this information, an estimated cost per cycle over the gooseneck can be calculated. This provides an estimate of the extent to which the pipe size will affect the overall economics of a prospective drilling operation. The next three tables show the cost per cycle over the gooseneck for each of the different completion sizes drilled. The information in this table is taken from the minimum flow rate requirements for the drill motor in that particular hole size, and the minimum hole cleaning pump rate.

Surface Casing SIZE & GAUGE	WEIGHT LB/FT	80 Yield	Cost/7000ft	Operating pressure	Rate	Cycles at pressure	Cost per cycle
2.00" + 0.204"	3.923	$5.22	$36,540.00	N/A psi	N/A	N/A	N/A
2.375" + 0.204"	4.742	$5.83	$40,810.00	4107 psi	5 bpm	70	$571.42
2.625" + 0.204"	5.288	$6.50	$45,500.00	2254 psi	5 bpm	105	$433.33
2.875" + 0.204"	5.834	$7.29	$51,030.00	1328 psi	5 bpm	100	$510.30

Table 9

Intermediate Casing SIZE & GAUGE	WEIGHT LB/FT	80 Yield	Cost/7000ft	Operating pressure	Rate	Cycles at pressure	Cost per cycle
2.00" + 0.204"	3.923	$5.22	$36,540.00	4081 psi	2.75 bpm	134	$272.68
2.375" + 0.204"	4.742	$5.83	$40,810.00	1500 psi	2.75 bpm	166	$245.84
2.625" + 0.204"	5.288	$6.50	$45,500.00	893 psi	2.75 bpm	134	$339.55
2.875" + 0.204"	5.834	$7.29	$51,030.00	593 psi	2.75 bpm	114	$447.63

Table 10

Production Casing SIZE & GAUGE	WEIGHT LB/FT	80 Yield	Cost/7000ft	Operating pressure	Rate	Cycles at pressure	Cost per cycle
2.00" + 0.204"	3.923	$5.22	$36,540.00	2945 psi	2.25 bpm	189	$193.33
2.375" + 0.204"	4.742	$5.83	$40,810.00	1186 psi	2.25 bpm	174	$234.54
2.625" + 0.204"	5.288	$6.50	$45,500.00	775 psi	2.25 bpm	134	$339.55
2.875" + 0.204"	5.834	$7.29	$51,030.00	580 psi	2.25 bpm	114	$447.63

Table 11

From tables 9,10 & 11 it can be seen that the cost per cycle changes based on the casing string drilled. At higher rates one string will outperform another with respect to cost. Based on these results, the 2.375-in. and 2.625–in. coiled tubing outperforms other string sizes. The 2.0–in. coiled tubing was not selected because it is not capable of drilling the surface casing.

Reel size directly affects the ease of transportation of coiled tubing on U.S. roadways and lease roads. If the reel is too large or too heavy, it may be necessary to obtain a permit before traveling on the U.S. roadway system. Permit specifics are addressed in great detail in Chapter 3. Reel size also influences trailer length and the resulting turning radius. Many lease roads are narrow with very tight-radius access roads. It is important that reel dimensions take into account an optimal turning radius and ease of permitting.

Table 12 displays reel dimensions based on 7,000 ft of coiled tubing required to drill a well of 6,000 ft TMD. The core diameter is the minimum core diameter for the pipe size. Although increasing the core diameter increases fatigue life, reel capacity for this exercise is optimized. The table shows the reel width and flange width combination required to hold a minimum of 7,000 ft of coiled tubing with 4 in. of freeboard based on 90 percent rap efficiency.

2.0" CT	Width	Core	Flange	Capacity
	14'	80"	105"	7000'
	13'	80"	110"	8247'
	12'	80"	110"	7658'
	11'	80"	110"	6951'
	10'	80"	115"	7804'
	8'	80"	115"	6214'
2-3/8" CT	Width	Core	Flange	Capacity
	14'	95"	120"	5053'
	14'	95"	125"	6894'
	13'	95"	130"	8114'
	12'	95"	130"	7555'
	11'	95"	130"	6995'
	10'	95"	135"	7722'
	8'	95"	135"	6178'
	8'	95"	140"	7364'
2-5/8" CT	Width	Core	Flange	Capacity
	14'	105"	135"	7000'
	13'	105"	135"	6410'
	13'	105"	140"	8195'
	12'	105"	140"	7577'
	11'	105"	140"	6958'
	10'	105"	140"	6185'
	10'	105"	145"	7587'
	8'	105"	145"	6000'
	8'	105"	150"	7235
2-7/8" CT	Width	Core	Flange	Capacity
	14'	115"	145"	5049'
	14'	115"	150	6880'
	13'	115"	150"	6491'
	13'	115"	155"	8298'
	12'	115"	155"	7621'
	11'	115"	160"	6774'
	11'	115"	160"	8310'
	10'	115"	160"	7686'
	8'	115"	160"	6232'
	8'	115"	165"	7429'

Table 12

Coiled tubing weight is the final consideration when selecting a pipe size for drilling. As the pipe OD increases, the overall string weight increases. This decreases the permissible weight for other items on the same trailer. The final design concept will determine the proportion coiled tubing weight will play in the design.

Table 13 lists coiled tubing string weight for 7,000 ft of coiled tubing for the given pipe size. In this comparison, all CT sizes use a 0.204–in. wall thickness.

Pipe Size	Weight for 7,000 ft
2.0"	27,461 lb
2-3/8"	33,194 lb
2-5/8"	37,016 lb
2-7/8"	40,838 lb

Table 13

Conclusion

The final coiled tubing selection depends upon many different factors. It is important to balance these factors and remain flexible with respect to the drilling operation. The coiled tubing pipe needs to be of a size that allows the equipment to travel down U.S. roadways under an annual permit, without escort vehicles. The size also needs to be large enough to perform all the required drilling operations.

Results demonstrated that the proposed well could be drilled with 2.375-in. or 2.625-in. coiled tubing. For purposes of wellbore cleanout and motor efficiency, however, 2.625–in. coiled tubing would be more appropriate.

Based on the performance results, the 2.875–in. coiled tubing had an advantage over 2.375–in. and 2.625–in. CT only from the point of view of flow rate and pressure.

Canadian coiled tubing drilling units use 2.875–in. coiled tubing for their drilling operations because the size reduces pump pressure sufficiently to not wear out the packing in their mud pumps.

While 2–in. coiled tubing could be used, it requires a specialized mud design to develop adequate hole-cleaning properties for the surface casing, and a specialized bit for drilling a large OD hole with a smaller motor. Pump pressures required for drilling with 2–in. CT are extremely high and can cause premature fluid pump packing failure.

Depending on the coiled tubing pipe size selected, it may be necessary to examine fluid pump selection because higher pump pressures can reduce the expected packing life and the efficiency of a pump. Coiled tubing drilling requires fluid pumps to operate for longer periods than they would for conventional coiled tubing operations. It is, therefore, common for a fluid pump to wear out before the operation is completed. If this happens, drilling operations are delayed until the pump can be rebuilt or another pump is put on line.

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Chapter

2

Mast height and hook load selection

This chapter compares rotary rig and coiled tubing drilling rig specifications to investigate the status of current technology. Tools and tool deployment are also examined to determine their effect on overall mast height.

This chapter outlines the factors that control the end design of the mast structure and floor height. Existing equipment, casing weight, casing lengths, injector dimensions, top drive specifications, tool deployment requirements and derrick configuration are addressed. It is the responsibility of the engineering team to use this information to optimize the derrick for size and weight.

Rotary rig specifications

The following table lists derrick and work floor specifications for rotary rigs that are currently working in our selected market.

Rig Type	Rated Depth (ft)	Load Rating (lb)	Derrick Height (ft)	Horse Power	Floor Height (ft)	Used Cost (US$)
Ingersoll Rand 20	6,500	120,000		700		
Failing 2000 HD	2,500		53	350		
Ideco H-35	6,500	180,000	95	350	12	460,000
Walker Neer AP 250-40	7,000	250,000	65		8	
Duggan DS-5	8,000	325,000	108	500		
Spencer Harris 7000	7,500	250,000	96	500		1,400,000 Package
National T-32	5,250	200,000	96	575	10	725,000 Package
Ideco H-37	7,000	224,000	103	400	11	500,000
Kremco		231,000	103			550,000
Bruster N-4	5,500	250,000	97		10	150,000
Wilson Mongul 42	8,000	250,000	97			1,400,000
Garner Denver 3000	4,200	160,000	95			
Bruster N-45	8,000	250,000	120		12.5	
Cabat 550	8,100	250,000	108		12	
Continental Emsco GB160	4,500	180,000	106		7.5	
Wichtex 4000	4,000	200,000	87			200,000
Wichtex 3500	3,500	150,000	70			345,000
Hopper Custom	5,000	180,000	96		8	
Custom	6,500	220,000	108		12	
Custom	5,500	180,000	90		8	

Source: Web Rig Sales

The following table lists coiled tubing drilling units that are currently operating in the Canadian drilling market.

Operator	Depth (ft)	Load Rating (lb)	Height (ft)	Injector Pull (lb)	Injector Type	Coil Size (in.)	Maximum Coil Length (ft)	Floor Height (ft)
Precision	4265	100,000	63	60,000	Fleet	2.375	2329	Variable
Precision	4265	80,000	74	60,000	Fleet	2.375	6135	Variable
Precision	6561	109,931	91	80,000	HR	2.875	6692	12
Precision	4265	80,000	74	60,000	Fleet	2.375	6135	12.3
TrailBlazer		98,915		80,000	S.S.	3.5		

Source: Operator Websites

Based on the preceding two tables, the minimum derrick height is 53 ft and the maximum derrick height is 120 ft. The mean derrick height is 86.5 ft, while the most common derrick height appears to be between 95 and 97 ft.

Load rating is a difficult number to generalize with rated depth because several factors contribute to the rated depth of a drilling rig. The most common limiting factor for depth is the horsepower rating of a rig. If the horsepower is too low to provide adequate pull on the draw works, the load rating of the derrick becomes irrelevant. Regardless of the rated depth, the two most common derrick load ratings are 180,000 and 250,000 lb. The coiled tubing drilling rig derrick load ratings are significantly less at 80,000–110,000 lb.

All floor heights listed in the tables refer to clear floor height, which is the clearance on the underside of the rig floor. This provides space for the drilling BOP stack, and ranges from 8–12.5 ft.

Casing weight is one of the main factors affecting the derrick load requirement. To determine a worst-case scenario for casing weight, the following tables are based on the theoretical wellbore schematic described in Chapter 1. The first table (below) lists the hook weights of various casing sizes in air. The highlighted values indicate possible loads based on the maximum depth for that completion size. The second table indicates what the hook load would be if the maximum completion length for each casing size were filled with kill weight fluid.

The following chart indicates the hook weight of different casing sizes in air.

Casing Size	Common Weight (ft)	1000 ft	2000 ft	3000 ft	4000 ft	5000 ft
9-5/8"	36	36,000	72,000	108,000	144,000	180,000
7"	23	23,000	46,000	69,000	92,000	115,000
6-5/8"	22	22,000	44,000	66,000	88,000	110,000
5-1/2"	15.5	15,500	31,000	46,500	62,000	77,500
4-1/2"	13.5	13,500	27,000	40,500	54,000	67,500
3-1/2"	11.2	11,200	22,400	33,600	44,800	56,000
2-7/8"	6.85	6,850	13,700	20,550	27,400	34,250

Indicates expected operating range.

From the previous table, select the maximum expected running depth and determine the casing's hang weight in air filled with 13.0 ppg kill fluid.

Casing Size	Common Weight (ft)	Casing Length (ft)	Cu. Ft/Ft	Weight of Fluid (lb)	Casing Weight (lb)	Total Weight (lb)
9-5/8"	36	2000	.4341	11,287	72,000	83,287
7"	23	3000	.221	8,619	69,000	77,619
6-5/8"	22	3000	.1956	7,628	66,000	73,628
5-1/2"	15.5	5000	.1336	8,684	77,500	86,184
4-1/2"	13.5	5000	.0838	5,447	67,500	72,947
3-1/2"	11.2	5000	.04587	2,981	56,000	58,981
2-7/8"	6.85	5000	.0325	2,112	34,250	36,362

The information gathered plus the application of a safety factor of 1.5 to 1 on the heaviest casing weight of 86,184 lb produces a maximum hook load of 129,276 lb. This load falls into the range of similar depth ratings shown by the various rotary rigs.

Derrick height is a function of tool deployment, rotary drive method, injector head and casing length. Several of these factors will combine to either increase or decrease the overall derrick height requirements. Therefore, it is important to understand how these factors affect one another during the coiled tubing drilling operation.

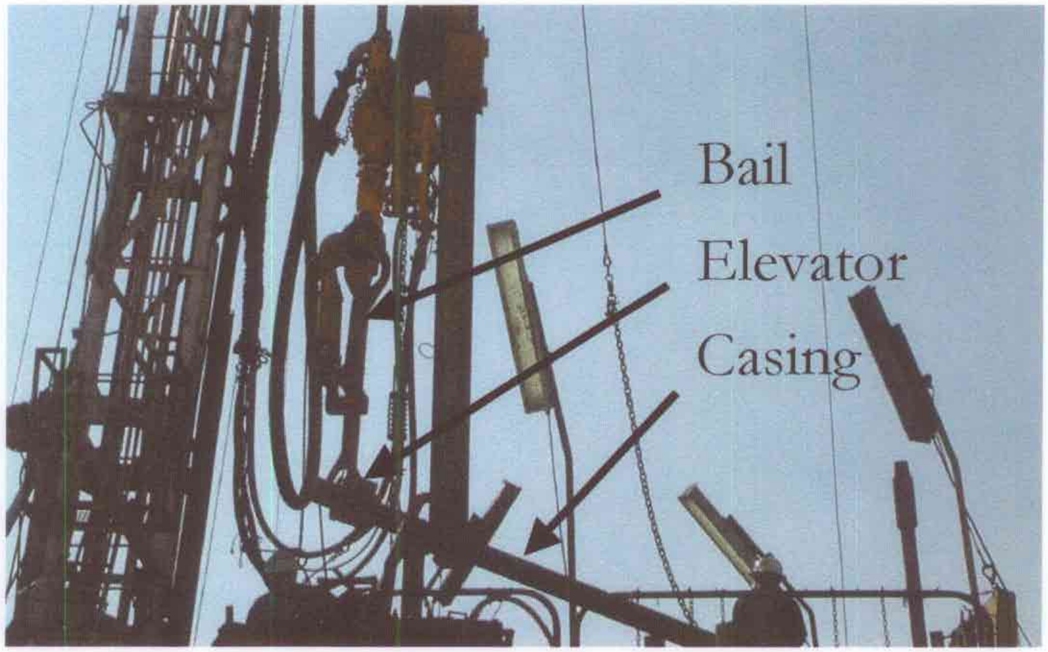
For the purpose of this exercise, it is assumed that the conductor will be rotary drilled with the coiled tubing unit. However, in many drilling operations the conductors are preset and grouted in place prior to their arrival. The conductor is set during the site-leveling and preparation phase of the operation. In other words, rotary drilling capability may not be needed at all for this unit.

Whether or not the end design includes rotary drilling capabilities, casing will need to be run. Casing and drillpipe are available in three different ranges based on length.

Casing	Range 1	16–25 ft
	Range 2	25–34 ft
	Range 3	34–48 ft
Drillpipe	Range 1	18–22 ft
	Range 2	27–30 ft
	Range 3	38–48 ft

Currently, Range 2 casing and drillpipe is the most popular size on the market. For that reason a triple stand is commonly referred to as 90 ft. However, Range 1 casing and drillpipe was used for years before Range 2 and Range 3 categories were introduced.

The derrick must be capable of raising the casing joint into the derrick above the previous joint run. Typically, casing is pulled into the derrick by using elevators and bails. The elevators and bails provide a means to catch the casing as it comes up the V-door ramp, and raise the casing or drillpipe into the derrick. The elevator and bail combination is typically 10–15 ft long. The determining factor is the distance between the well center and the V-door opening. The following figure shows casing being caught before it is raised into the derrick.



The derrick height can be reduced by 10–15 ft if an alternative method for catching casing is developed.

Injector height is only a factor in underbalanced operations, when the BHA is lubricated instead of slick line-deployed. If the BHA is lubricated, the derrick must be capable of raising the injector on top of the lubricator. For some underbalanced operations the BHA can be as much as 70–80 ft in length.

Currently, there are only two injector heads available on the market which ptimize the weight and dimensional requirements required to remain within road legal limits:

Stewart and Stevenson
Series 800 Injector
Maximum Pull 80,000 lb

Maximum Snub	20,000 lb
Tubing sizes	1-1/4 in. – 3-1/2 in.
Chains	Removable inserts
Weight	6,500 lb without gooseneck
Dimensions	H 81 in. x W 42 in. x D 54.5-in.

DCT Coiled Technology, Inc
Model 8500
Maximum Pull 85,000 lb

Tubing sizes	1-1/4 in. – 4 in.
Chains	Removable inserts
Weight	7,680 lb without gooseneck
Dimensions	H 83 in. x W55 in. x D 54 in.

Because the dimensions are similar on both injectors, we can assume the 83-in. height of the DCT injector for determining mast height requirements.

Top drive height becomes a factor if the unit is to have rotary drilling capability. Similar to the top drive is the power swivel. The differences between the two are discussed in Chapter 10.

Currently TESCO manufactures a small fit-for-purpose top drive system for the shallow coal bed methane market. The dimensions and specifications for TESCO T75 top drive system are shown below.

SPECIFICATIONS:

T75 / T100 (Integrated Swivel)	100Ton		75Ton	
Rated Capacity	100 ton	91 tonne	75 ton	68 tonne
Pull Down Capacity @ 50 RPM	20 ton	18.2 tonne	20 ton	18.2 tonne
Tonnage @ 100 RPM	100 ton	91 tonne	75 ton	68 tonne
Weight (with swivel)	6,000 lbs	2 730 kg	5,500 lbs	2 500 kg
Operating Length (incl. 8 ft. links & elevator)	140 in.	3 556 mm	140 in.	3 556 mm
Width	42.75 in.	1 086 mm	42.75 in.	1 086 mm
Max. Drill Torque (ΔP=4,000 psi)	18,600 ft-lbs	1 372 daN-m	18,600 ft-lbs	1 372 daN-m
Make-up Torque (ΔP=4,000 psi)	18,600 ft-lbs	1 372 daN-m	18,600 ft-lbs	1 372 daN-m
Breakout Torque (ΔP=4,500 psi)	21,100 ft-lbs	1 556 daN-m	21,100 ft-lbs	1 556 daN-m
Max. Speed (with 1.96 gears, @170GPM)	181 RPM	181 RPM	181 RPM	181 RPM
Quill ID	2.5 in.	63.5 mm	2.5 in.	63.5 mm

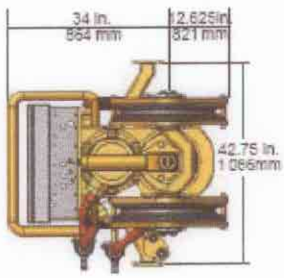
Top Drive Notes:

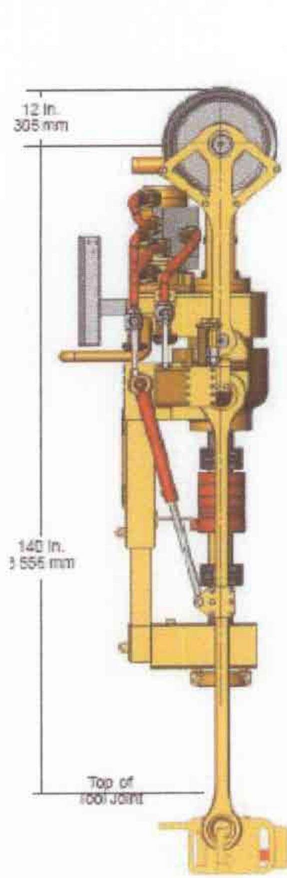
Weight includes top drive, integrated swivel and split blocks

Alternate block adaptors available for the T100 & T75

Power Unit Notes:

AC induction motor, DC traction motor drive, or modularized hydrostatic sub-assemblies are available

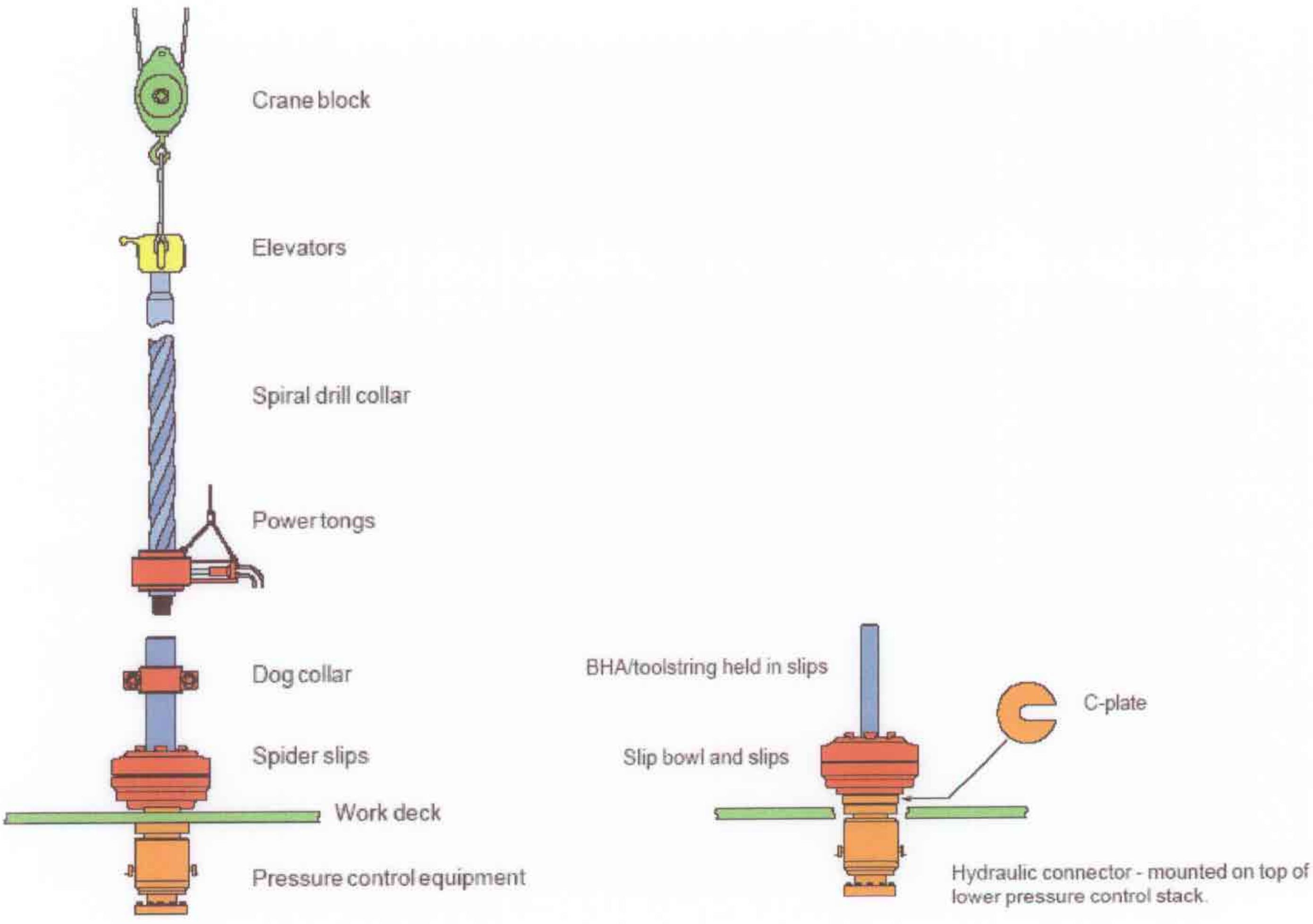




Tool deployment can be performed by several different methods, depending on the condition of the well. If the well is overbalanced or at balance, the tools can be lowered into the well with the well open to atmosphere. If the well is underbalanced, the tools must be pressure-deployed, lubricated, or deployed against a downhole deployment valve.

Overbalanced tool deployment is the simplest method of deploying long tool strings. During overbalanced tool deployment, each tool section is lowered into the well and hung off by slips and a dog collar for safety. The next tool joint is then raised into the derrick and made up on top of the lower tool joint. The dog collar and slips are removed and the tool joint is lowered into the well. This process is repeated until the entire tool joint is installed in the well.

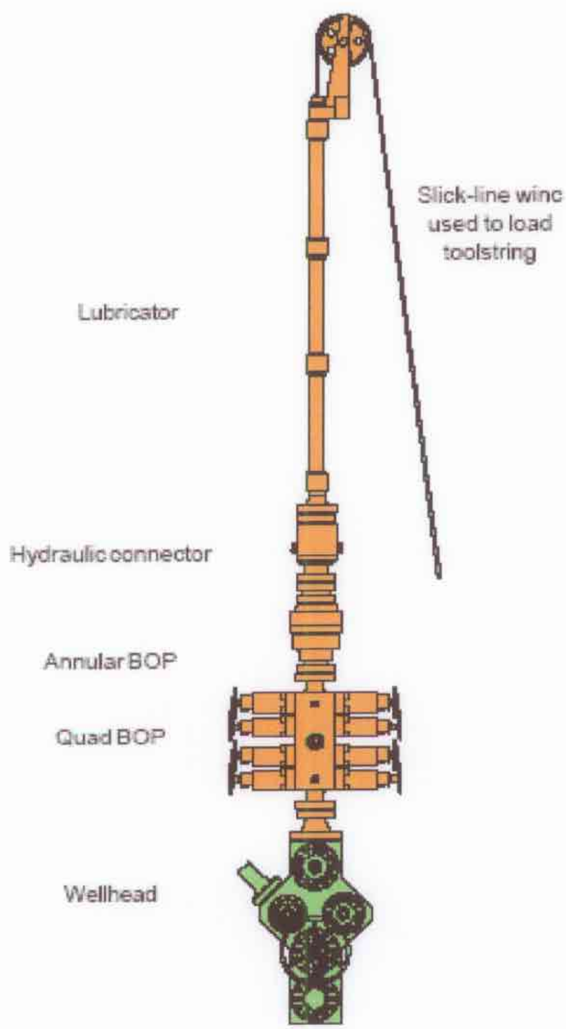
The following figure depicts overbalanced tool deployment.



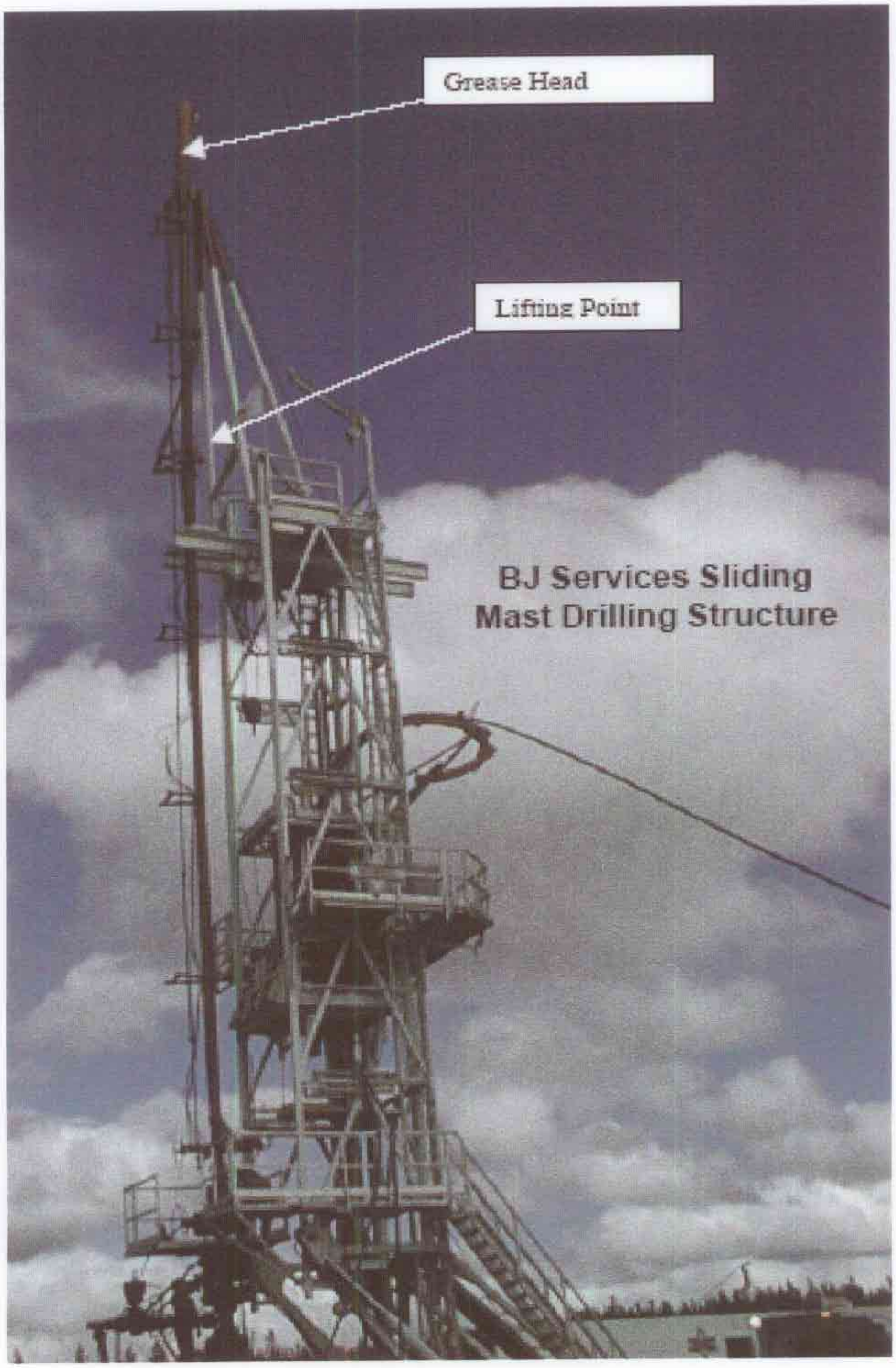
Underbalanced drilling requires the tool string to be pressure-deployed. Several options are available for deploying underbalanced. The first is to have a long lubricator section that can house the entire tool string length, and a structure that can support the injector above the lubricator. The second method is to use a subsurface deployment valve; and the third method is the use of slickline to deploy the tools.

In order to limit the height of the derrick and maintain flexibility in tool strings, slickline deployment methods are recommended for underbalanced operations. This allows the entire derrick height to be used for tool deployment. Slickline deployment methods require only the injector head to travel over a short riser section that hides the connection between the deployment bar and the coiled tubing. A disadvantage of slickline deployment is the need for an extra BOP for the pipe and slip rams.

The following figure depicts a typical slickline deployment rig-up.



The BJ Services mast drilling unit demonstrates how slickline deployment can be incorporated into a coiled tubing drilling rig. The following figures show the equipment BJ Services uses to deploy their DUCT coiled tubing drilling BHA.

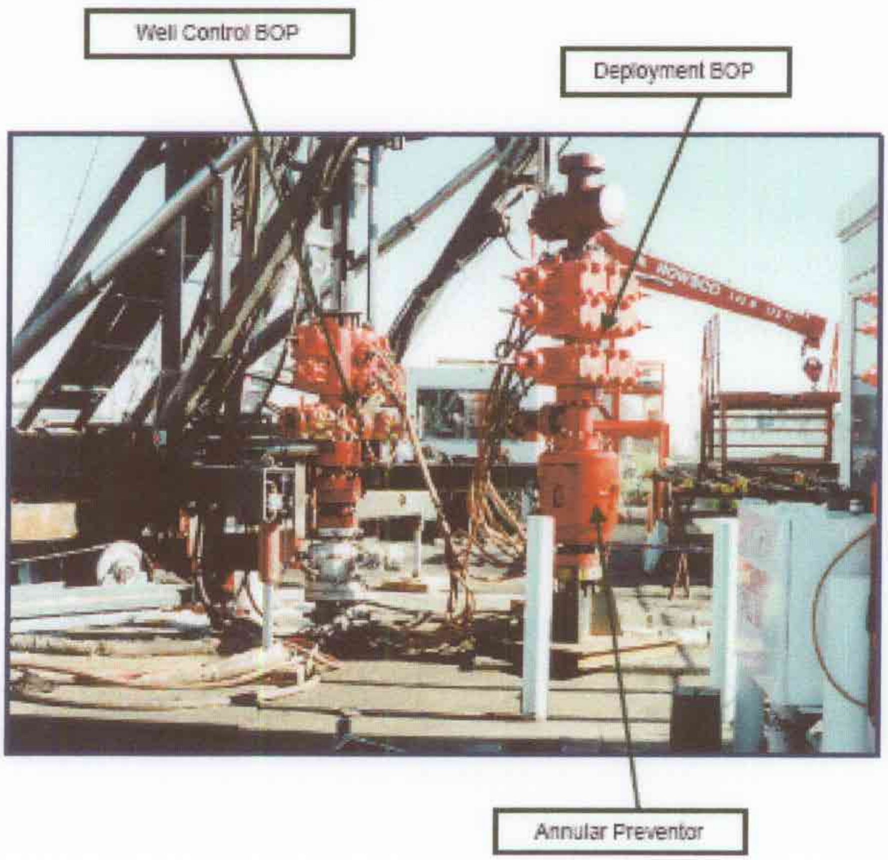


Deployment Riser:

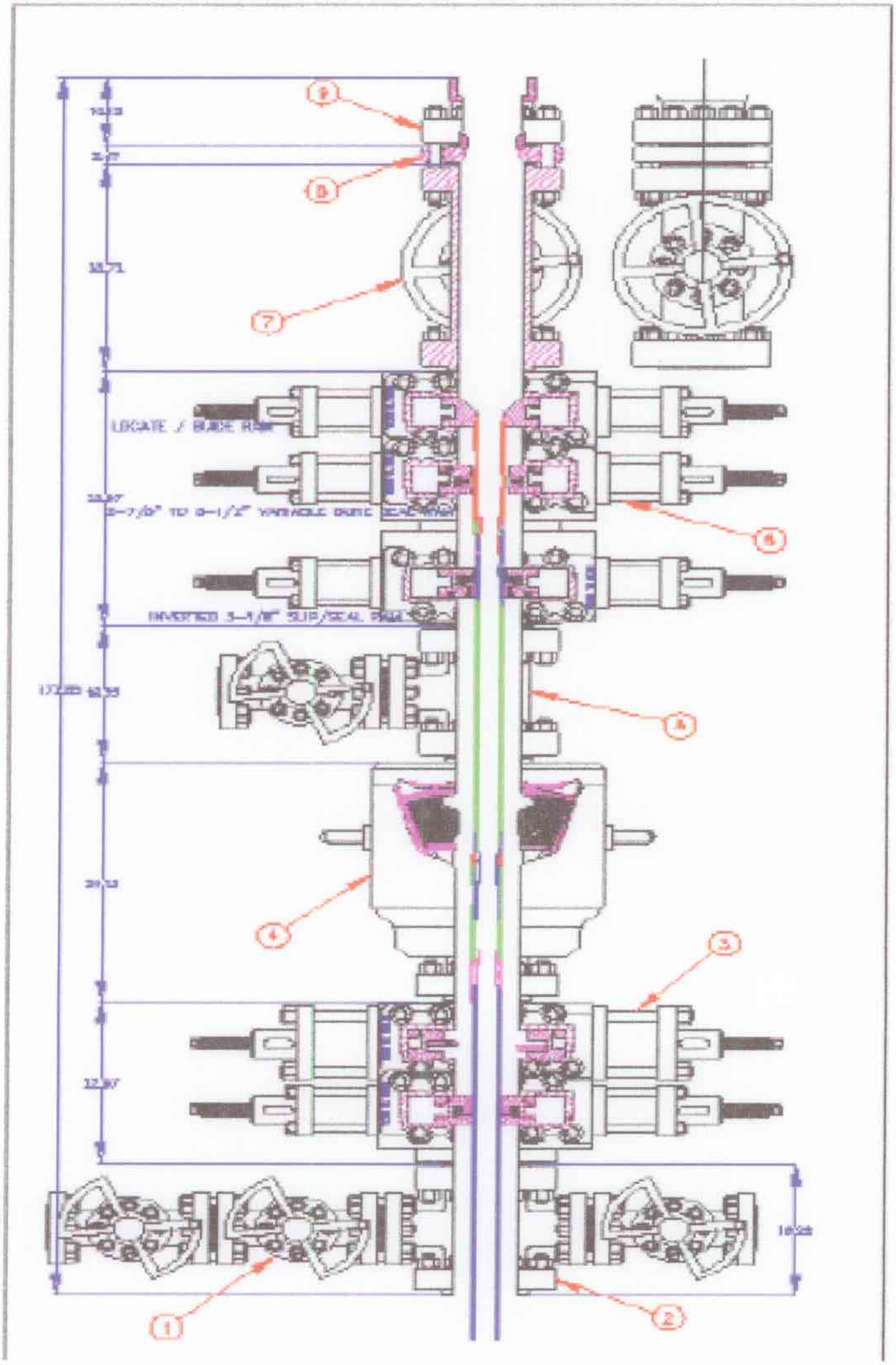
<u>Well Controll BOP and Deployment BOP System:</u>

Weights:

- Drilling BOP: 9100 lbs.
- Deployment BOP: 6500 lbs.

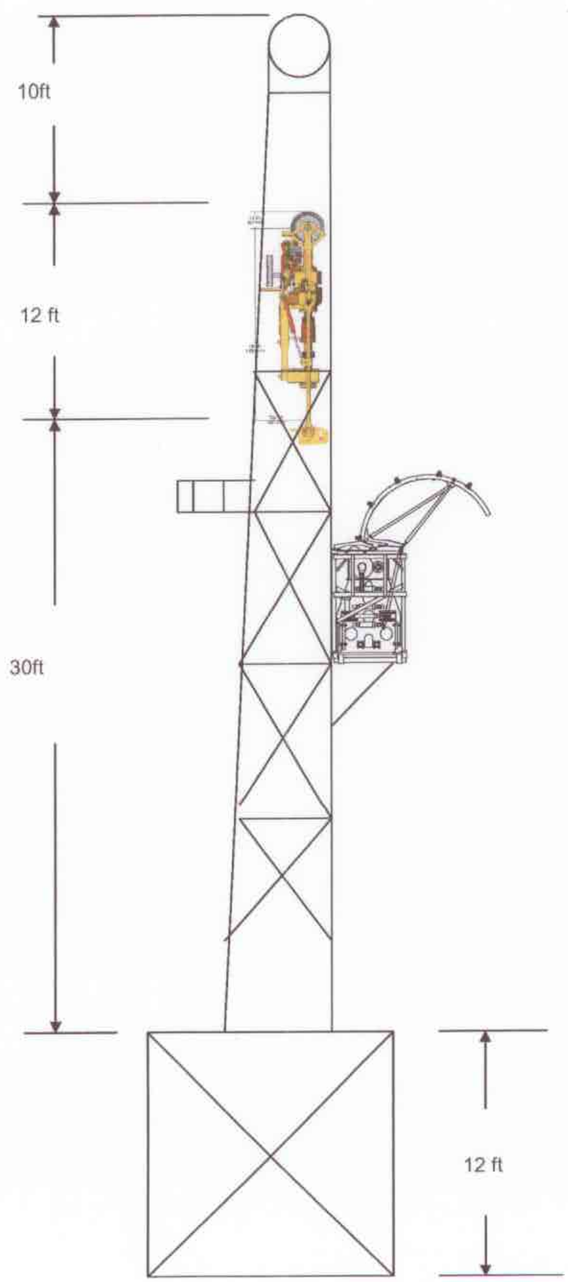


Well Control and Deployment BOP Schematic:



Derrick configuration

The following diagram shows the minimum derrick height that can be achieved using the Foremost style of derrick design. The diagram illustrates where and how it may be possible to reduce the derrick height requirements.



Conclusion

Tool deployment presents the greatest challenge when reducing the mast or derrick height. The longest indivisible tool joint can be expected to be approximately 35 ft long. Space also needs to be allotted for the installation and handling of the tool joint. Depending on the operation, this could mean an extra 5-10 ft over the actual tool joint length.

When designing the derrick, it is also important to remember that tool joints may need to be exchanged for bit swaps or motor swaps during the drilling process. The derrick needs to be designed to accommodate this operation.

Based on the consistency of the data, a 12-ft clear height is a good starting point for designing the rig floor height. Floor height will ultimately be dictated by the ability to clear and maintain the BOP stack.

A good starting point for derrick loading is 130,000 lb. However, an API shop that builds mast structures should have the deciding input into actual requirements. Any experienced rig manufacturer can provide the minimum derrick load capacity based on projected completion sizes and depths.

Chapter

3

Maximum permitable loads

This chapter addresses the criteria for obtaining an annual over-dimension or overweight permit.

This chapter determines maximum allowable trailer dimensions and escort requirements for the purpose of obtaining an annual permit in each state. The dimensions cited in this section are the maximum allowed to qualify for an annual permit without an escort vehicle.

The legal limits and their effects on our project are explained in the following paragraphs.

On January 6, 1983 the federal government enacted the Surface Transportation Assistance Act of 1982 (STAA). This act established uniform weight, length and width requirements for vehicles using the interstate and other federally assisted highways.

The STAA has imposed the following maximum limits for all vehicles using federal and federally assisted highways.

Width:	**102 in.**
Length:	**Semi-trailers – at least 48 ft**
Weight:	**One axle 20,000 lb**
Tandem axles:	**34,000 lb**
Gross allowable weight:	**80,000 lb**
Compliance with federal bridge formula:	**$W = 500\ [LN/(N-1) + 12N + 36]$**

Definitions

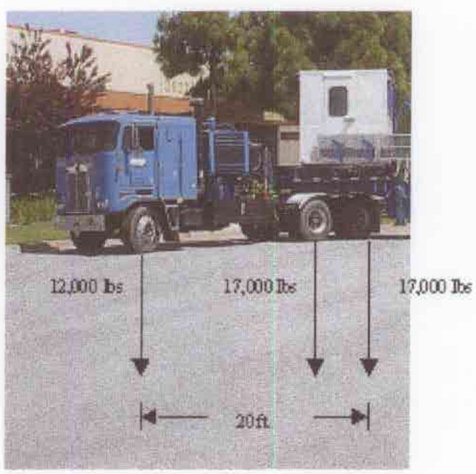
Gross Weight – The weight of a vehicle or vehicle combination plus the associated loads

Single Axle Weight – The weight on one or more axles whose centers are less than 40 in. apart

Tandem Axle Weight – The total weight on two or more consecutive axles that are between 40 and 96 in. apart

Note: The single and tandem axle weight limits supercede the bridge formula when axle spacing falls into the range of the previous definitions. When axle spacing falls outside the single and tandem axle definitions, the federal bridge formula is the limiting factor, regardless of the single and tandem limits.

Use of the bridge formula is very straightforward, but requires a tractor-trailer combination to be looked viewed in three different configurations. First, the tractor weights alone are determined; then the tractor-trailer combination; and finally, the trailer and drive wheel combination. The following is an example of the bridge formula for a tractor-trailer combination.



Actual weight = 12,000 + 17,000 + 17,000 = 46,000 lb

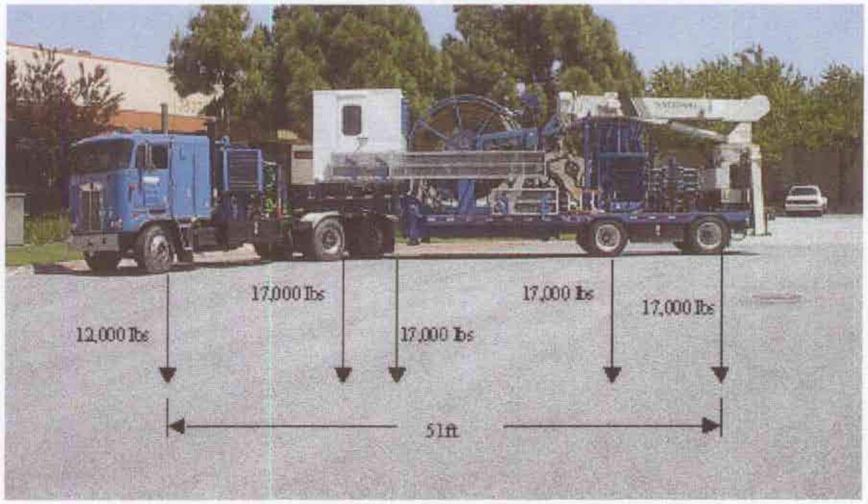
N = 3

L = 20

W = 500[LN/(N-1) + 12N + 36]

W = 500[(20 x 3)/(3-1) + (12 x 3) + 36] = 51,000 lb

W exceeds the actual weight; therefore, the tractor loading is acceptable.



Actual weight = 12,000 + 17,000 + 17,000 + 17,000 + 17,000 = 80,000 lb

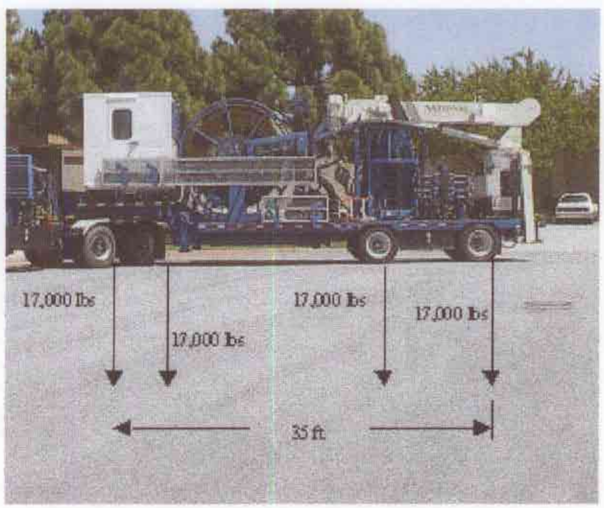
$N = 5$

$L = 51$

$W = 500[LN/(N-1) + 12N + 36]$

$W = 500[(51 \times 5)/(5-1) + (12 \times 5) + 36] = 80,000$ lb

W equals the actual weight; therefore, the tractor-trailer loading is acceptable.



Actual weight = 17,000 + 17,000 + 17,000 + 17,000 = 68,000 lb

$N = 4$

$L = 35$

$W = 500[LN/(N-1) + 12N + 36]$

$W = 500[(35 \times 4)/(4 - 1) + (12 \times 4) + 36]$

$W = 65,333$ lb

W is less than the actual weight; therefore, in this instance the truck exceeds the limits set forth by the bridge formula. Either the weight must be reduced, or the trailer made longer.

The following spreadsheet shows the legal limit and the maximum limit for vehicles granted an annual permit without the use of an escort vehicle. There may be sign requirements for any of the loads running under an annual permit.

It is important to note that for all overweight permits it is necessary to comply with some form of the bridge formula or maximum axle loading requirement.

						Permitable Limits with no escort required				
	State	Legal Width	Legal Height	Legal Length	Legal Weight lbs	Permitable Width	Permitable Height	Permitable Length	Permitable Weight	Comment
WASHTO States	Colorado	8.5 ft	13 ft	70 ft	80,000	14 ft	14 ft	110 ft	Color Coded Bridge Syste	Maximum Bridge Load Quad axle
	Arizona	8.5 ft	13.5 ft	65 ft hwy 57	80,000	12.5 ft	14 ft 8 i	80 ft	160,000 gross	
	Idaho	8.5 ft	14 ft	75 ft	105,000	12.5 ft	14 ft	100 ft	105,000	
	Montana	8.5 ft	14 ft	53 ft Trailer	132,000	12.5 ft	14.6 ft	110 ft	Axle Dependant for annual	
	New Mexico	8.5 ft	14 ft	57.5 ft Traile	80,000	8.6 - 14ft May nee	14 ft	90 ft	Permit Dependant	
	Oklahoma	8.5 ft	13.5 ft	70 ft	80,000	12 ft	14 ft	80 ft	108,000	Weight limited by turn pike. Maximum weight per axle 20,000 lbs
	Oregon	8.5 ft	14 ft	56 Trailer	80,000	Map Dependant	14 ft	95 ft	98,000 (Sign Req)	
	Texas	8.5 ft	14 ft	59 Trailer	80,000	12 ft	14 ft	110 ft	120,000 gross	
	Utah	8.5 ft	14 ft	65 ft	80,000	12 ft	14 ft	105 ft	125,000 gross	
	Washington	8.5 ft	14 ft	75 ft	105,500	11 ft	14.6 ft	75 ft	160,000 gross	
SASHTO States	Arkansas	8.5 ft	13.5 ft	53.5 ft Traile	80,000	12 ft	15 ft	75 ft	180,000	Single Trip Permits Only
	Alabama	8.5 ft	13.5 ft	53 ft Trailer	80,000	10 ft	14 ft	75 ft		
	Florida	8.5 ft	13.5 ft	53 ft Trailer	80,000					Over Dimensional and Over weight Not allowed on Annual permit
	Georgia	8.5 ft	13.5 ft	53 ft Trailer	80,000	12 ft	14.5 ft	100 ft	100,000	
	Kentucky	8.5 ft	13.5 ft	53 ft Trailer	80,000	10.5 ft	13.5 ft	75 ft		
	Lousiana	8.5 ft	13.5 ft	59.5 ft Traile	80,000	12 ft	14 ft 4 i	90 ft		
	Mississippi	8.5 ft	13.5 ft	53 ft Trailer	80,000	10 ft	14 ft	99 ft	120,000	10 Day permit available under
	Missouri	8.5 ft	13.5 ft	53 ft Trailer	80,000	12 ft 4 in	13.5 ft	90 ft	108,000 six axle	
	North Carolina	8.5 ft	13.5 ft	53 ft Trailer	80,000					Annual permit exists but is not
	Ohio	8.5 ft	13.5 ft	53 ft Trailer	80,000	11 ft	13.5 ft			
	Oklahoma	8.5 ft	13.5 ft	53 ft Trailer	80,000	12 ft	14 ft	80 ft		
	South Carolina	8.5 ft	13.6 ft	53 ft Trailer	80,000	12 ft		125 ft		
	Tennessee	8.5 ft	13.5 ft	53 ft Trailer	80,000	12.5 ft	13.5 ft	85 ft		
	Texas	8.5 ft	14 ft	59 Trailer	80,000	12 ft	14 ft	110 ft	120,000 gross	
	Virginia	8.5 ft	13.5 ft	53 ft Trailer	80,000	14 ft	14 ft	100 ft	115,000	
	West Virgina	8.5 ft	13.5 ft	53 ft Trailer	80,000					Single Trip Permits Only
	Alaska	8.5 ft	14 ft	53 ft Trailer	80,000		10 ft	75 ft	125% of legal axle group	
	California	8.5 ft	14 ft	65 ft		15 ft (Sign Req)	Check f	135 ft	28,000 max axle group	
	Connecticut	8.5 ft	13.5 ft	48 ft Trailer	80,000	12 ft	14 ft	80 ft		No Annual Permit Available
	Delaware	8.5 ft	13.5 ft	60 ft Trailer	80,000	12 ft	15 ft	85 ft	120,000	Single Trip Permits Only
	Illinois	8.5 ft	13.5 ft	53 ft Trailer	80,000	14.5 ft	14.5 ft	110 ft		Single Trip Permits Only
	Indiana	8.5 ft	13.5 ft	53 ft Trailer	80,000	12 ft 4 in	13.5 ft	110 ft	Single Trip Only	
	Iowa	8.5 ft	13.5 ft	53 ft Trailer	80,000	13.5 ft	13.5 ft	120 ft	156,000	
	Kansas	8.5 ft	14 ft	59.5 ft Traile	80,000	14 ft	15 ft	126 ft	120,000	
	Maine	8.5 ft	14 ft	53 ft Trailer	80,000				Single Trip Only	
	Maryland	8.5 ft	13.5 ft	53 ft Trailer	80,000	12 ft	14 ft	75 ft	80,000	
	Massachusetts	8.5 ft	13.5 ft	53 ft Trailer	80,000	12 ft	13.5 ft	80 ft	130,000	
	Michigan	8.5 ft	13.5 ft	53 ft Trailer	80,000	12 ft	14 ft	85 ft	150,000	
	Minnesota	8.5 ft	13.5 ft	53 ft Trailer	80,000	14.5 ft	13.6 ft	85 ft	145,000	
	Nebraska	8.5 ft	14.5 ft	53 ft Trailer	80,000					Six month permit issued for only a single county operation. No
	Nevada	8.5 ft	14 ft	53 ft Trailer	129,000	14 ft	12 ft	105 ft		
	New Hampshire	8.5 ft	13.5 ft	53 ft Trailer	80,000	10.5 ft	13.5 ft	75 ft	80,000	
	New Jersey	8.5 ft	13.5 ft	53 ft Trailer	80,000					Annual not available
	New York	8.5 ft	13.5 ft	53 ft Trailer	80,000	10 ft	13.5 ft	72 ft	Calculate	
	North Dakota	8.5 ft	13.5 ft	53 ft Trailer	80,000					Single Trip Permits Only
	Pennsylvania	8.5 ft	13.5 ft	53 ft Trailer	80,000	11 ft	13.5 ft	90 ft		Single Trip Permits Only
	South Dakota	8.5 ft	14 ft	53 ft Trailer	80,000	14.5 ft	14 ft	60 ft		
	Vermont	8.5 ft	13.5 ft	53 ft Trailer	80,000	12 ft	13.5 ft	68 ft	108,000	
	Wisconsin	8.5 ft	13.5 ft	53 ft Trailer	80,000	12 ft	13.5 ft	100 ft	170,000	
	Wyoming	8.5 ft	14 ft	60 ft Trailer	80,000	12 ft	15 ft	75 ft		

WASHTO states. There are ten western states that make up WASHTO: Arizona, Colorado, Idaho, Montana, New Mexico, Oklahoma, Oregon, Texas, Utah and Washington. These states have joined together to allow carriers needing oversize/overweight permits for operation on highways and the regional network a standard permitable load. Each jurisdiction may issue and collect fees and allow operations in all other member jurisdictions. The following limitations apply:

- ➤ Length 110 ft overall
- ➤ Height 14 ft
- ➤ Width 14 ft
- ➤ Weight 160,000 lb gross weight

  21,500 lb single axle

  43,000 lb tandem axle

  53,000 lb per tandem (wheelbase between 8–13 ft)

The single trip permit is valid for a period of five working days for the given permitted vehicle only.

SASHTO states: Sixteen states have joined together to allow vehicles to obtain an oversize/overweight permit that is valid in all nine states. The member states are Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Mississippi, Missouri, North Carolina, Ohio, Oklahoma, South Carolina, Tennessee, Texas, Virginia and West Virginia. The limits for this permit are as follows:

- ➤ Length 100 ft
- ➤ Height 14 ft
- ➤ Width 14 ft
- ➤ Weight 120,000 lb

  20,000 lb single axle

  40,000 lb tandem axle

  60,000 lb three or more axles

The single trip only permit is valid for a period of ten days.

A market analysis was performed to look at the possible areas of operation. The study attempted to identify areas in which shallow drilling is currently taking place and the level of activity in those areas. The results of this study can be seen on the following map. The circled numbers indicate the number of wells drilled within a 200 mile radius. The 200 mile radius represents a commutable distance from a central hub.

Total wells less than 5,000 ft in 2003/2004
By radius of travel

The map shows two major areas of interest the Mid West and the North Eastern region. The following table compares annual permit limits for these selected states.

	Permitable Limits with no escort required				
State	Permitable Width	Permitable Height	Permitable Length	Permitable Weight	
Colorado	14 ft	14 ft	110 ft	Color Coded Bridge System	
Montana	12.5 ft	14.6 ft	110 ft	Axle Dependant for annual	
New Mexico	8.6 - 14ft May need escort	14 ft	90 ft	Permit Dependant	
Texas	12 ft	14 ft	110 ft	120,000 gross	
Oklahoma	12 ft	14 ft	80 ft		
Kansas	14 ft	15 ft	126 ft	120,000	
Wyoming	12 ft	15 ft	75 ft		
Michigan	12 ft	14 ft	85 ft	150,000	
Pennsylvania	11 ft	13.5 ft	90 ft		Single Trip Permits Only
Ohio	11 ft	13.5 ft			
West Virgina					Single Trip Permits Only

The table shows that a single trip permit will be required in the eastern states whether or not the legal limits are exceeded. There for we will focus on the western states with regards to trying to stay under weight and dimensional limits for obtaining annual permits

Conclusion

In most states it is possible to obtain an annual permit for over-dimensional and overweight vehicles. In the majority of these states the limit for over-height under an annual permit is either 14 ft or the state legal limit. Over-width is generally limited by the need for an escort vehicle. Most states require an escort vehicle when width exceeds 12 ft. The typical allowable overall tractor/trailer length under an annual permit is 90–110 ft.

An annual permit can be easily obtained in most states if a reasonable width, length and weight are selected. In most states, an annual permit is available for widths over 12 feet up to a maximum of 14 feet, but these dimensions require an escort vehicle; going over height, on the other hand, makes an annual permit very difficult to obtain.

Chapter

4

BOP Requirements

This chapter examines BOP requirements based on API specifications.

BOP requirements are dictated by the governing body of each state, based on the formation to be drilled. Formation data is used to estimate maximum bottomhole pressures and flow rates. Based on this information, a minimum stack requirement is placed on the permit to drill.

The American Petroleum Institute (API) has established a guideline API RP53 to categorize the type of BOP stack required by different pressure categories. This guideline addresses diverter, BOP, annular BOP and drilling spool requirements.

In addition to individual state requirements are the internal requirements for BOP stack equipment set forth in Sclumberger's standards 22 and 22a. Standard 22a is the coiled tubing drilling standard. This standard covers the BOP requirements for drilling and makes an allowance for a 5,000 psi BOP stack, which might be a far higher pressure rating than would normally be required in some areas. At this time it does not appear that a 5,000 psi BOP will add significantly to the BOP stack height and weight

Excerpt from Standard 22a

9. BOP/Wellhead Equipment

The exact BOP/wellhead configuration will depend on several factors relating to hole and casing sizes, underbalance-overbalance, and any unique features of the well being drilled. As a minimum, the following must be used: Means of closing on size of CT being used (CT sealing ram)

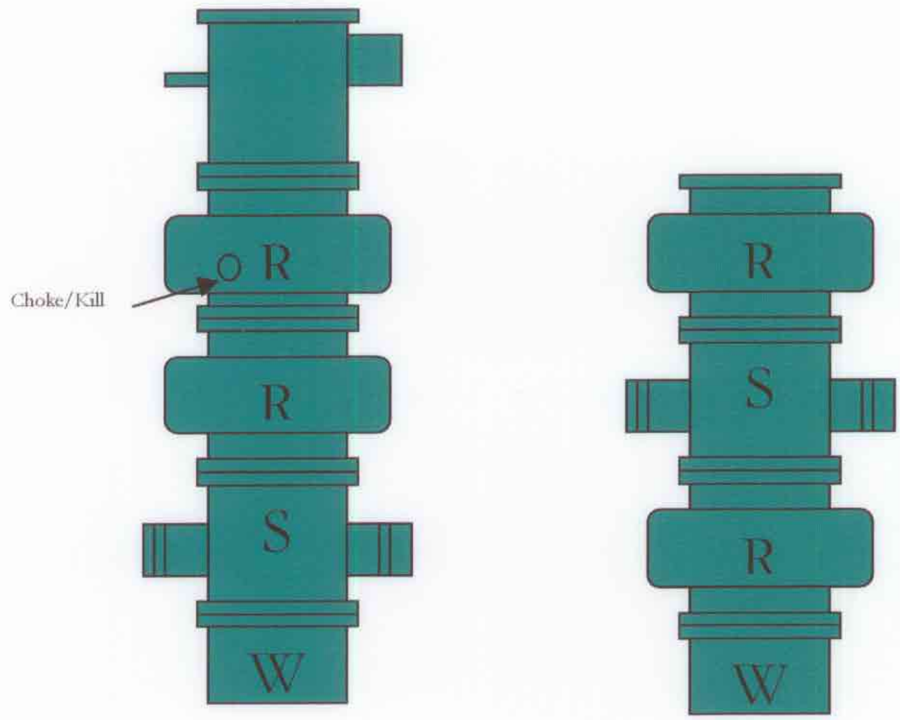
- *Means of gripping the CT being used (slip-type ram)*
- *Means of shearing/ sealing the CT being used (shear/ seal ram)*
- *Means of closing in on anything larger or smaller than CT (annular BOP)*
- *Means of closing wellbore with nothing in the well (shear – seal, or blind rams)*
- *Two outlets on the BOP stack to allow flow in and out of the wellbore for well-kill operations*
- *Inside BOP/ safety valve to fit BHA (kept on rig floor at all times)*
- *Float valve below lowest BHA item (just above motor)*

Ws STD 22 A – Coiled Tubing Drilling Safety Standard (8.5)

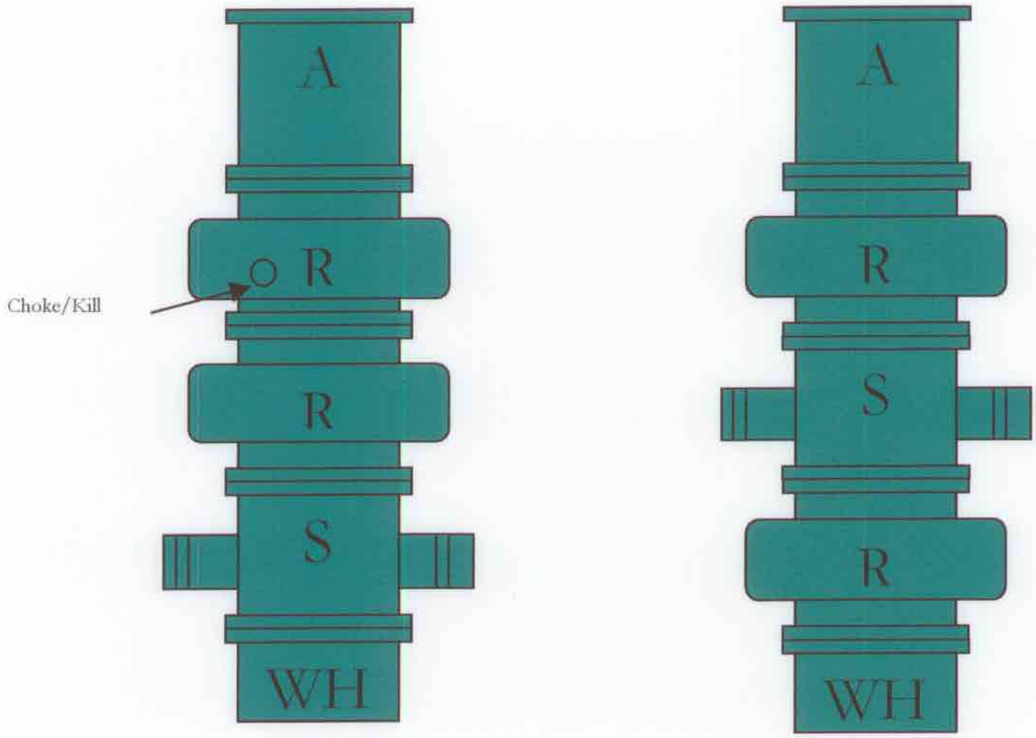
Regardless of the pressure category, a minimum stack requirement will be outlined by the individual state in which the well is drilled, and will also be influenced by API RP53.

The following BOP schematics are based on different pressure categories.

Example arrangements for 2K-rated working pressure service



Example arrangements for 3K- and 5K-rated stacks

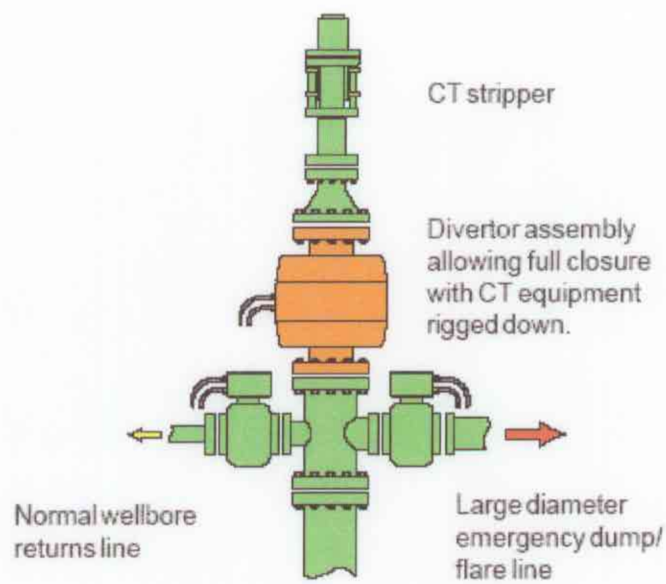


A = Annular BOP

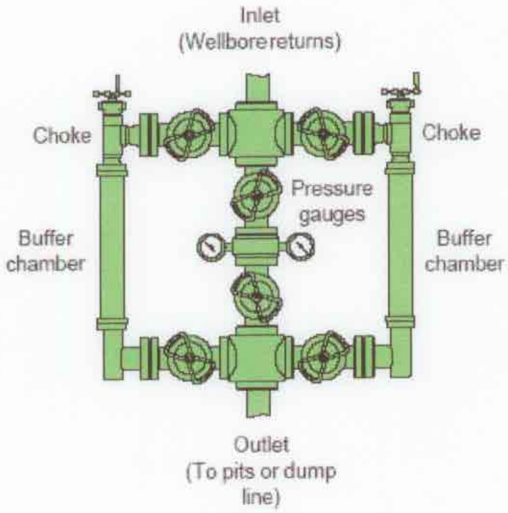
R = Single ram-type BOP

S = Drilling spool with side outlets

A diverter line is used in top hole sections where formations cannot withstand shut-in pressures. Some areas require the use of a diverter as a safety precaution, regardless of conditions. A diverter is an annular preventer coupled with a large diameter piping system underneath. It is used when conductor pipe is set and is used to divert flow and gas from the rig. Diverter systems are designed for high flow rates and low pressure. To minimize erosion, flow lines should be large and as simple as possible. A diverter system typically has two flow lines to allow for changes in wind direction. The following figure represents a typical diverter arrangement for a coiled tubing drilling operation.



The last piece of well control equipment is the choke manifold. The choke manifold controls the flow rate to the pit in the event of a kick or maintains desired back pressure. Most choke manifolds incorporate two individual chokes as a means to divert flow in case one choke becomes plugged. A standard choke manifold design is illustrated below.



Conclusion

The BOP stack configuration will be determined on a well-by-well case basis as determined by the individual state governing body.

State requirements may be exceeded by Schlumberger internal standards. Further research needs to be made into exactly how state and Schlumberger standards compare so that the well control stack can be optimized for safety and efficiency.

Diverter lines must be run if there is ever the possibility of encountering shallow gas. The diverter line should be run away from the drill site downwind. If necessary, the diverter line should be connected to a flare stack.

Chapter

5

BHA Requirements

Drilling a wellbore from surface with coiled tubing requires many different BHA assemblies. This chapter outlines the different BHA assemblies and how they can affect the end design of a coiled tubing drilling rig.

The BHA for any drilling operation largely depends on the type and complexity of the drilling operations and the conditions in which these operations will be conducted. Based on the complexity of the drilling operation, a BHA may be made up of several different components that serve various functions.

Typically, BHA assemblies are configured according to the drilling operation they will perform. There is a difference between standard BHA applications, which can be summarized as vertical applications, and those applications that are directional. Vertical applications include new wells and well deepenings, while directional applications include electric telemetry or mud pulse technology.

The following figures illustrate the standard components of the different types of BHA for each application. These figures are only a representative sample of what each BHA diagram may look like; other combinations are possible, and actual BHA dimensions will vary by vendor and according to the completion size to be drilled.

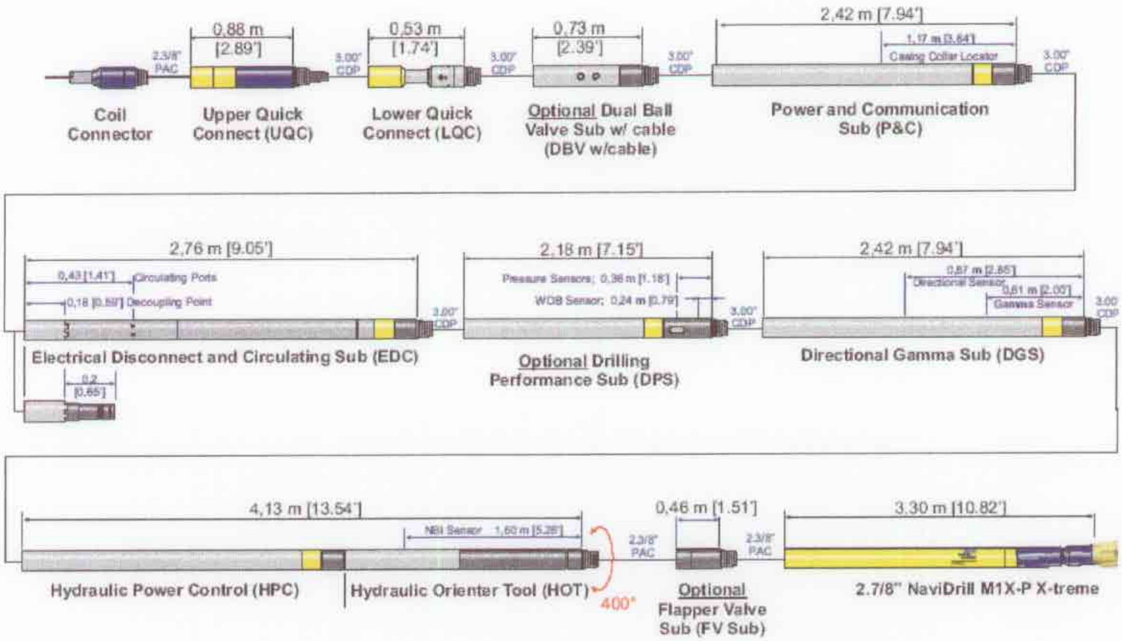
Vertical Drilling BHA

Length	Component	Description
1 ft.		Coil connector
2.5 ft		Check Valve
2 ft		Release Joint
+/- 100 ft		Drill Collar
10-25 ft		Motor
1 ft		Drill Bit

Horizontal Drilling BHA

Length	Component	Description
1 ft		Grapple connector
2.5 ft		Dual Flapper Valve
2 ft		Release Joint
25-34 ft		Survey and Acquisition tools
13-15 ft		Orienting Tool
10-25 ft		Motor
2-4 ft		Bent Sub
1		Bit or Mill

Wired Horizontal BHA Assembly



Source: Baker Hughes

Conclusion

Vertical drilling requires the rig to handle drill collars, which are a maximum length of 30 ft. It would be advantageous to the operation if the derrick was able to stand up the BHA in the derrick for ease of deployment. This would also make motor and bit swaps more efficient.

Horizontal drilling may require a lubricator system for pressure-deploying the tool string. Because of the extremely long length of the tool strings, it will probably be necessary to install the BHA in multiple sections with deployment bars. The longest section length is 35 ft. Additional length, typically 4–6 ft, is added for the deployment bar itself.

The largest OD of the BHA would be a 6 1/2–in. motor with a 10 5/8–in. bit. Drill collar ODs may very according to hole size. These ODs influence the ID of the well control equipment and lubricator. For horizontal work the largest OD will be a 5 7/8-in. bit; this dimension controls the pressure deployment lubricator ID.

Chapter

6

Operational procedures

This chapter provides an overview of the general procedures for all coiled tubing drilling applications. Some finer details may not be included here as they may be too specific.

This chapter provides an outline of coiled tubing drilling procedures according to type of operation. Both overbalanced and underbalanced drilling operations are addressed, though this does not necessarily mean that both operations will be performed during the same drilling operation. However, it is possible that both operations may be required in the same well, but at different stages of the operation.

The initiation of different underbalanced drilling techniques such as foam drilling, misting and gas drilling are also discussed, whether or not these techniques will actually be used.

Site Preparation

STEP	Procedure	Details
1	Prepare access road to location.	Ensure that all access roads are wide enough for the turning radius of all trucks needing entrance to location.
2	Level site.	Level site large enough to spot all necessary drilling equipment. Uneven ground will reduce the derrick lift capacity.
3	Verify well location.	Ensure that the pad to be drilled is the correct wellsite.
4	Set conductor.	Have conductor rotary rig come in and set conductor based on well plan/grout in place.
5	Rig up starter head.	Have certified welder weld starter head onto conductor.
6	Set tie-down anchors as needed.	Position anchors based on well center position.
7	Plan well site layout.	Determine arrival order and position of equipment on location. Tight locations may not allow equipment to be turned around once other equipment is brought onto location.

Notes:

Rig-Up Procedure

STEP	Procedure	Details
1	Hold pre-rig-up meeting.	Discuss equipment positioning, job responsibilities and safety concerns.
2	Bring in CT drilling rig.	Spot drilling rig over well center.
3	Bring in pipe trailer.	
4	Bring in mud system.	
5	Bring in returns tank.	
6	Bring in pump skids.	
7	Bring in generator system/hydraulic unit.	
8	Bring in water tank.	
9	Bring in parts trailer.	
10	Bring in chemical trailer.	
11	Bring in diesel tank.	
12	Connect electrical circuits.	Connect all skid units that require electrical power to generator unit.
13	Connect hydraulic circuits.	Connect all hydraulically driven units to hydraulic power source.
14	Raise mast.	Elevate mast and guy down as needed.
15	Nipple up BOP stack.	Connect BOP stack to starter head.
16	Run lines.	Run lines from pumps to BOP stack, CT reel and mud system.
17	Run lines.	Run lines from mud system to flow lines on BOP stack.
18	Position pipe racks.	Position pipe racks next to pipe trailer.
19	Unload BHA and drill collars.	
20	Fill water tank.	Bring in vacuum trucks to fill tanks.
21	Perform systems check on equipment.	Perform visual inspection of equipment; check that equipment has been assembled properly. Check all fluid levels.
22	Stab coiled tubing.	Perform this step if unit does not come pre-stabbed.
23	Prime fluid pumps.	
24	Perform pressure test on all fluid lines.	Check that all valves and lines are holding.
25	Pressure test BOP stack.	
26	Transfer water to mud system.	
27	Start gelling fluid.	Mix drilling fluid as specified in the drilling program..

Notes:

BHA Pick-Up Procedure – for Surface String/Intermediate String (Overbalanced)

STEP	Procedure	Details
1	Pull first drill collar to rig floor.	With hydraulic winch or air tugger pull drill collar to drill floor.
2	Screw in lift sub.	Screw lift sub into place and tighten with a 36–in. pipe wrench. Make sure rotary connection is shouldered up.
3	Latch lift sub.	Latch hold of lift sub with required elevators.
4	Lift drill collar into derrick.	Drill will pick up on blocks while the roughneck tails the drill collar into the derrick.
5	Make up drill collar to PDM motor and bit.	Screw on bit using the right torque and pipe dope. A bit breaker is used to hold the bit from spinning when torquing the connection.
6	Record drill collar displacement values.	Metal displacement of drill collar.
7	Check floor valve.	Make sure that the proper crossover sub is on the floor for the floor valve to connect to the top of the drill collar for well control.
8	Check well conditions.	Verify that well is at balance before opening.
9	Open well slowly.	
10	Run drill collar and bit into well.	
11	Set slips.	Driller stops blocks and energizes the slips.
12	Install drill collar clamp.	Also known as dog collar.
13	Slack off blocks.	
14	Remove lift sub.	
15	Pick up next lift drill collar.	With hydraulic winch or air tugger pull drill collar to drill floor.
16	Install and inspect lift sub on next drill collar.	
17	Make up drill collars.	Screw drill collars together using proper torque and pipe dope. Use makeup and breakout tongs or a top drive and breakout tong combination to torque the connection.
18	Repeat Step 11 through Step 17.	Repeat Step 11 through Step 17 until all drill collars are made up.
19	Connect CT lubricator.	Connect any necessary lubricator to the bottom of the injector head to hide the motor head assembly during connection to well head.
20	Run pipe down.	Run coiled tubing down so connection can be made to end of coiled tubing.
21	Connect motor head assembly.	Connect coiled tubing motor head assembly to the end of the coiled tubing. Typical motor head assembly includes CT connector, check valves and release joint.
22	Connect to drill collars.	Connect motor head assembly to drill collars.
23	Unset slips.	Pull out of hole with coiled tubing and support weight of drill string with coiled tubing. Pull slips and remove drill collar clamp.
24	Connect to BOP.	Lower injector and connect injector lubricator to top of BOP stack.
25	Test connection.	RIH far enough to close pipe rams around coiled tubing and pressure-test connection.

Note: In some cases it is not possible to deploy the full drill collar length required due to the shallow depth of the conductor. In such cases it is necessary to drill ahead with coiled tubing until enough hole has been drilled to allow the remaining drill collars to be picked up. At this time, pull out of hole to surface and break off the motor head assembly from the drill collars. Complete Step 11 through Step 17 until all drill collars have been connected, then proceed with Steps 18 through 25. It may be necessary to run stabilizers at 30, 60, and 90 ft to help to maintain a true vertical well.

Pressure Deployment

STEP	Procedure	Details
1	Measure tools string.	
2	Pick up required lubricator.	
3	Make up crossover.	Cross over from slick line tool string to deployment bar on first section of tools.
4	Install tools.	Pull tools into lubricator and position lubricator over CT BOP.
5	Make up lubricator.	Connect lubricator to CT BOP and bump tool string up against stuffing box.
6	Zero counter.	
7	Confirm RIH depth.	Confirm RIH depth against measurements to ensure deployment bar is placed across pipe rams and slips, leaving enough of the bar above the BOPs to make up and break out the tool string.
8	Slowly open swab valve.	This equalizes the wellbore pressure in the lubricator. **Caution: Opening the swab valve too fast can blow wireline tools up hole and result in breaking the wire line and dropping the tools.**
9	Run tools into wellbore determined depth.	
10	Close pipe and slip rams on deployment bar.	
11	Pull test against slips.	
12	Bleed pressure off lubricator.	
13	Carefully raise lubricator.	Expose deployment bar and break out.
14	Repeat Step 7 through Step 13 for additional segments.	

Notes:

Deploying Injector

STEP	Procedure	Details
1	Pick up injector and required length of lubricator to cover remaining segment of tool string.	
2	Attach remaining tools to deployment bar.	Record weight-indicator weight before connecting to deployment bar.
3	Strip lubricator over tool string and make up lubricator to BOP.	
4	Ensure all injector settings are reset for running in hole.	Reset inside chain tension to prevent ejection from well.
5	Open slip rams.	
6	Open pipe rams.	Open equalizing port on BOP to prevent damage to pipe ram seals.
7	Zero counter.	Zero counter and POOH to tag stripper. Record distance for reference when reverse deployment is performed.

Initiating Overbalanced Drilling

STEP	Procedure	Details
1	Prepare drilling mud.	Gel drilling fluid according to drilling program/
2	Determine weight on bit.	Determine BHA hang weight in fluid and calculate necessary snub or pull weight needed to provide optimum weight on bit.
3	Break circulation.	Record pump pressure and rate.
4	Tag bottom and start drilling.	Monitor pump pressure and adjust penetration rate based on pressure response. Pressure will increase if penetration rate is too great as motor will stall.
5	Perform wiper trips.	Perform wiper trips as needed to keep wellbore clean of excessive filter cake.

Notes:

Initiating Underbalanced Drilling

Gas Drilling

STEP	Procedure	Details
1	Drill out shoe.	Drill out shoe with water or mud.
2	Pump slugs of gas.	Alternate slugs of gas with water. Do not use mud.
3	Pump 5 gallons of foaming agent.	Once most of the water is out of the hole, pump foaming agent and circulate it to remove water.
4	Go to bottom and repeat process.	
5	Light flare line.	
6	Drill one tool joint.	
7	Repeat. 1-6	Continue repeating until well makes dust.

If after 2 hours the well has not dusted, add 5 gallons of foamer and begin the process again with Step 3.

Initiating Misting

STEP	Procedure	Details
1	Unload well with air.	Do not dry hole.
2	Light flare line.	
3	Drill one foot of formation.	
4	Pick up one tool joint.	Continue Steps 3 and 4 for at least 5 feet. If no drag is recorded, continue.
5	Steady returns.	Wait for steady continuous mist to form before adjusting mist volume or mixture. Wait a minimum of 30 minutes after each adjustment before proceeding with further adjustments.

Initiating Foam Drilling

STEP	Procedure	Details
1	Unload well with air.	Do not dry hole.
2	Check pit volume and separator volume.	
3	Start foam pump and compressor.	
4	Drill one foot of formation.	
5	Pick up one tool joint.	Continue Steps 3 and 4 for at least 5 feet. If no drag is recorded, continue.
6	Steady returns.	Wait for steady continuous mist to form before adjusting mist volume or mixture. Wait a minimum of 30 minutes after each adjustment before proceeding with further adjustments.

Hole Cleaning

STEP	Procedure	Details
1	Pull off bottom.	
2	Drop circulating sub ball.	Perform this procedure only if a circulating sub was installed in the BHA. Circulating sub will prevent motor from excessive rotation during hole cleaning operations.
3	Open circulating sub.	
4	Increase pump rate.	Record pump rate and pressure.
5	Pump one bottoms up.	Circulate one hole volume of clean drilling mud.
6	Check well control conditions.	Circulate weighted pill around if needed to regain balance.
6	Pull out of hole while circulating.	This will help carry any remaining cuttings to surface.

Lay Down Procedure (Overbalanced Procedure)

STEP	Procedure	Details
1	Check well control conditions.	Pump weighted pill if needed.
2	Pull out of hole.	Watch weight indicator for excessive pull weights.
3	Slow down POOH 100 ft from surface.	
4	Tag stripper.	
5	Stop any pumping.	
6	Check well control conditions.	
7	Break off lubricator.	
8	Raise injector head and set slips.	
9	Connect drill collar clamp.	
10	Slack off on injector pipe weight.	
11	Disconnect coiled tubing motor head assembly.	
12	Lay down absorbent on pipe rack .	This is used to absorb fluids that will drain off the drill collars as they are pulled.
13	Connect lift sub to drill collar.	
14	Connect elevators to drill collar.	
15	Pull drill collars in reverse order of their installation sequence.	
16	Break out drill motor and bit for inspection.	Inspect drill motor and bit for wear.

Lay Down Procedure (Underbalanced Procedure)

STEP	Procedure	Details
1	POOH until connector tags stripper.	Do not exceed weak point when tagging if e-line is used.
2	Zero counter.	RIH to pre-recorded depth in coiled tubing deployment procedure.
3	Close slip rams on deployment bar.	Visually verify closure.
4	Bled pressure off above pipe rams.	Ensure rams are not leaking before proceeding.
5	Strip lubricator up to expose deployment bar.	
6	Break connection at deployment bar.	Watch for trapped pressure.
7	Lay down tools and rig off injector.	

8	Move in deployment lubricator.	
9	Make up crossover to slickline tools.	
10	Make up lubricator and pressure test.	
11	Equalize pressure below tubing rams into lubricator.	
12	Pull test connector.	
13	Open rams.	
14	Pull up hole until tool string tags stuffing box.	
15	RIH to recorded depth.	Recorded depth in Step 7 of deployment procedure.
16	Close pipe and slip rams on deployment bar.	Check that slips are holding by slacking off weight.
17	Bleed pressure off lubricator.	
18	Break off lubricator to expose connection.	
19	Repeat Step 9 through Step 12.	
20	Once all tools are clear of swab valve, close the valve.	
21	Bleed off lubricator, lay down tools.	

Running Casing

Preparation

STEP	Procedure	Details
1	Racking	✓ Verify correct casing. ✓ All casing handled with thread protectors in place. ✓ Store casing on racks. ✓ Compare delivery note with number of joints delivered. ✓ Rack joints in order in which they are required. ✓ Distinguish different weights, grades and threads. ✓ Separate all damaged joints and return. ✓ Number remaining joints.
2	Numbering	✓ Number each joint with paint. ✓ Remove all other old markings. ✓ Use different paint color than any existing marking.
3	Measuring	✓ Use only steel tape measure. ✓ Measurements are made by 2 individuals using different measuring devices. ✓ Discrepancy in measurements greater than 1 inch should be re-measured. ✓ Measurements should be taken from pin end to box end. The makeup loss should be deducted.
4	Drifting	✓ Ensure drifts are correct for casing weight being run. ✓ Reject any casing that does not drift.
5	Threads	✓ Inspect threads after they have been cleaned. ✓ Replace protectors after inspecting threads. ✓ Apply pipe dope to threads at entrance to V-door, not over the rotary, to prevent dope brush from falling inside the casing.
6	Centralizers	✓ Verify centralizer schedule against casing numbering to

		ensure proper installation,
7	Rig preparation	✓ Wear bushing has been retrieved. ✓ Correct BOP rams have been installed and tested. ✓ Block line visually inspected and ton/mile record checked. ✓ Maximum available overpull with casing has been calculated and recorded. ✓ Casing fill-up line is ready for operation. ✓ Casing swages are of proper size and pressure rating. ✓ All tank level sensors are working. ✓ Drill pits have enough space for displaced fluid. ✓ Side-door elevators have been inspected. ✓ Casing thread dope is on location. ✓ Thread locking compound and cleaning materials are on location. ✓ Power tong torque calibration has been checked. ✓ Draw works brake system has been checked. ✓ Elevator links are long enough for cement equipment.
8	Running list – items to be considered or noted	✓ Date, well name, casing size, drill floor elevation and casing specifications ✓ Landed depth ✓ Depth of float collar ✓ Position of different weights and grades of casing, if applicable ✓ Stick-up of the casing at drill floor when cementing ✓ Position of centralizers and cement baskets in the hole ✓ Minimum and maximum makeup torques ✓ Depths where casing shoe enters open hole, washouts, tight spots and loss zones
9	Running casing	✓ Correct makeup torque has been applied. ✓ Float collar does not allow back flow. ✓ Circulation through float equipment is possible. ✓ Displaced mud is diverted to the same tank that the fill-up line draws from. ✓ Each joint is completely filled. ✓ Specified running speeds are not exceeded. ✓ Centralizers are installed as specified in the program. ✓ Circulation is broken at previous shoe before entering open hole. ✓ Spiders are to be used for

		running casing in open hole. ✓ Surge losses are minimized by reducing running speed. ✓ No joints are removed from rig site before end of job.
10	After running casing	✓ Ensure correct number of joints remain on surface. ✓ Circulate minimum of 120% of casing volume. ✓ Perform pump test to determine maximum pump rate achievable before losses occur. ✓ If hole packs off or hanger starts to plug, cut pump strokes immediately to avoid fracturing formation. ✓ Check circulation at intended cement displacement rates. ✓ Check mud properties.

Cementing Casing

STEP	Procedure	Details
1	Cement lines	Ensure all cementing lines are properly pressure tested.
2	Cement head	Ensure that cement manifold valves are properly set and that the correct cement plugs have been loaded.
3	Recording hardware	Ensure that all recording hardware is functional to record density, rate, pressure and volume.
4	Verify pump time	Calculate mixing time, pump time and displacement time and check against slurry thickening time to ensure adequate time for pumping.
5	Load tickets	Check load ticket for adequate volume and correct additives.
6	Verify water	Strap water tank to ensure sufficient water is on location for mixing and displacement if displacing with water.
7	Ensure return tank volume	Ensure that there is enough space in the return tank to take all the returned mud and slurry from the cement job.
8	Mud scale	Ensure that a pressurized mud scale is available in the event of densitometer failure.
9	Samples	Take sample of dry blends, mix water, and pumped cement out of each bottle.
10	Pump schedule	Verify pump schedule with driller. Check cement volumes to ensure proper placement and fill-up heights. Verify displacement volume. Will cement be placed on top of the plug?
11	Mix and pump	Mix and pump cement according to schedule.
12	Drop plug	Drop wiper plug.
13	Displace	Displace cement at predetermined rate. Slow down rate 10 bbl before bumping the plug.
14	Bump plug	Bump the plug 500 psi over circulating pressure and shut down pumps. Surge back and bleed off pressure to displacement tanks. Verify float holding. If float does not hold pressure up to

		1000 psi, surge back. Test the float for holding.
15	Wash up	Make sure that all equipment through which returned cement travelled is cleaned thoroughly.

Directional Drilling

STEP	Procedure	Details
1	Make up bit	✓ Place bit into bit breaker and install makeup clamp. ✓ Install articulation stiffeners to protect bent sub from makeup torque. ✓ Torque bit.
2	Configure motor	✓ Hang motor in elevators. ✓ Access bent sub adjusting ring. ✓ Follow manufacturer's instructions for setting bent sub angle. ✓ Tighten adjusting ring and check setting.
3	Make up BHA	✓ Run in hole with motor. ✓ Mark the high side scribe line on the motor as it goes in. ✓ Install clamp on top of motor and remove lift sub. ✓ Check the float installation in the float housing. ✓ If float is not installed, break float housing and install float. Re-torque after installing. ✓ Install orienting tool by aligning with high scribe mark. ✓ Install and torque remaining BHA.
4	Shallow hole test	✓ Bring pumps to speed and check for motor rotation and leaks in the motor articulation.
5	Drilling curve	✓ RIH to 20–30 ft off bottom hole. ✓ Slowly bring pumps up to speed to establish circulation. ✓ Confirm MWD is functioning. ✓ Orient motor as necessary. ✓ Slowly RIH and add weight to bit. ✓ Monitor drill face heading as curve starts to build. ✓ Verify drill face heading. ✓ Start drilling curve.

Chapter

7

New technology

This chapter describes new internal technology that has potential value for this project.

The purpose of the coiled tubing microhole drilling unit is to drill microholes efficiently and inexpensively. Those technologies that can contribute directly to a reduction in the overall cost or which can improve the efficiency of the operation are discussed in this chapter. These technologies meet the following criteria:

- Value to operation
- Cost associated with implementing technology
- Ease of integration
- Ability to integrate at a later time

OpsCAB

- OpsCAB is a clean, relatively low-cost control system that can bring value to the project based on the following features:
    - Injector speed control
    - Injector slip control
    - Automatic pull test
    - Overpull and snubbing
    - Skate and stripper pressure leakage detection
    - Automatic reel tension adjustment RIH and POOH
    - Automatic reel brake release
    - Automatic tubing lubrication capacity
    - BOP closure detection
- OpsCAB is designed to be a low-cost control system and should be competitive from a cost point of view with any other control system.
- OpsCAB is designed to tie directly into existing coiled tubing hydraulic circuits. Integration with any coiled tubing package is therefore very straightforward. Field testing of OpsCAB installed on a standard hydra rig coiled tubing unit has already been completed.
- OpsCAB is fairly simple to integrate at a later time except for the redundancy of control systems, unless the old control system were completely removed.

InterACT

- InterACT is a wellsite monitoring system that transmits wellsite information via the satellite back to users who are logged onto the InterACT website.

InterACT is valuable as a wellsite monitoring system for standard coiled tubing operations. The system does not currently have a display for handling pertinent drilling information, which would make it even more valuable to the operation.

- The cost of InterACT will depend on the choice of satellite phone carrier, but is not projected to be an overly large expense.
- The system is easily installed.
- InterACT is simple to integrate at any time.

CT InSPEC

- CT InSPEC is a continuous ovality and wall thickness monitoring system. Wall thickness is a concern with coiled tubing strings that are in service for long periods of time or which pump large volumes of corrosive fluids. Because a string will not have sufficient life for excessive wear or corrosion to occur, fatigue life should be the failing criteria of the microhole coiled tubing unit. CT InSPEC will contribute value to the project by its ability to certify that a string has a certain wall thickness remaining if it is resold for a completion.
- Costs for CT InSPEC have not yet been established. However, each unit will probably cost a considerable amount.
- The CT InSPEC system is straightforward to install.
- CT InSPEC is simple to integrate at any time.

Technology Development

- Integrate pump and choke controls with the OpsCAB package.
- Integrate mud system and pit alarms with the OpsCAB package.
- Develop a driller's report that will automatically update with current drilling activity when selected.

Develop or identify robust non-rotating stab in BHA connections to reduce BHA makeup time.

Chapter

8

Automated controls

This chapter focuses on the areas in which automated controls add value to the drilling operation.

Automated control systems have become extremely sophisticated, and today are quite common on large, high-dollar offshore drilling rigs. Rigs use this automation because time can mean serious money, and automation is one way to save considerable time in an operation.

For our model, time is not as large a factor as manpower and safety. Therefore, this section focuses primarily on the ways in which automation can reduce manpower and improve operational safety.

The amount of equipment on location, and the need to monitor the operation of that equipment, directly governs the manpower required on a drilling operation. Combining control functions, monitoring gauges, and employing remote visual capability are all methods of reducing manpower.

The following list describes the equipment used in a typical drilling operation and the personnel required for each piece of equipment.

Drilling

Coiled tubing unit – requires a single operator located at the control console (operator cannot leave position while drilling).

Fluid Pump – requires a single operator, unless the operation is controlled from the CT console (operator cannot leave position while drilling).

Mud System – requires a mud engineer and an operator. The operator is optional if a camera system is installed to watch returns. Pit alarms can handle outflow and inflow from the well. The mud engineer is on location, but does not stay on pits except to take routine measurements. The pit operator must remain on pits during the entire operation to verify that circulation is not lost.

Choke Manifold – this is usually manned by the same operator who monitors for returns. The position could be eliminated by bringing choke control into the console.

Hydraulic power pack – requires an occasional walk around by the operator to perform a visual inspection of the unit. Vital operating parameters should be displayed in the console.

Generators – these require an occasional walk around by the operator to perform a visual inspection of the unit. Vital operating parameters should be displayed in the console.

Running Pipe

Block – requires one person.

Tongs – requires two people for the top drive, but could conceivably be performed by one individual. However, this function would involve a considerable amount of activity for a single person during the pipe running operation.

Pipe rack – requires one person.

Therefore, even though manpower can be significantly reduced by automating the control system while drilling, it still requires a certain number of people to run pipe. In addition to the automated functions, a minimum crew would need to include a supervisor, coiled tubing operator, and two hands.

Drillers reports are required on every drilling operation. These reports require the driller to manually record data already monitored and recorded by a standard coiled tubing drilling unit. If this monitored and recorded data could be pulled and inserted directly into the drillers report, it would take less time from the driller and ensure greater accuracy of the data recorded.

An example of a standard drilling report is provided on the next two pages. It is important to note that this example does not represent the only format in use, and that this particular report does not necessarily include all the data that may contribute useful value.

COILED TUBING DRILLING DAILY REPORT

Report Nr 23
page 1 of 2

Oilfield Services District:	Location:	Report Date:	3-Sep-98
Operator:	Well No:	Well Type:	Gas Injector
CTD Rep.:	Company Rep.:		
Signature:	Signature:		

BHA RECORDS

Run No.: 14	Drill Open Hole			Run No.: 15			
Item	ID No.:	OD"	Length	Item	ID No.:	OD"	Length
Coil Connector	U111024	2.875	0.94	Coil Connector	U111024		0.94
OrientXpress upper	CT05102	3.125	3.15	OrientXpress uppe	CT05102		3.15
OrientXpress orienter	CT02100	3.125	34.39	Xpress orienter	CT02100		34.39
Flapper valve sub	CT10102	3.125	0.75	Flapper valve sub	CT01102		0.75
Rlease tool 105Kn	CT01102	3.125	2.85	Release tool 105K	CT01102		2.85
Motor 1.37 deg	A14352-8	2.875	11.14	Motor 0.35 deg	A14351-2		10.96
Tricone Bit	S89YY	3.5	0.49	PDC Bit	1207446	3.5	0.62
Cum Length in ft			53.51	Cum Length in ft			53.66

Run Time / Depth

Run No.:	14
Time In	15:15 hrs 1 Sept
Depth in	7846 ft
Depth Out	8315 ft
Time Out	11:00 hrs 3 Sept
Run hrs.:43.75	Run ft. 9069ft

Bit Type:Hughes Chr. GT-20
TFA:0.415, Volume pump.985bl
Grade: 1/1/No/Al/3/I/no/BHA

Run No.:	15
Time In	13:30 3 Sept
Depth in	8315 ft
Depth Out	
Time Out	
Run hrs.:	Run ft.: xxxx ft

Bit Type:R335G Hughes Chrt
TFA:4x12
Grade:

DRILLING

Start Date - Drilling	30-Aug-98		Drilling Fluid	Sea Water	
Previous MD	7,955	ft	Current Fluid Weight	8.6	ppg
Present MD @ 23:59	8,503	ft	Av. Pump Rate	1.8	bpm
Total Length Drilled	947	ft	Av. Press on Btm	1800	psi
24 hr Drilling Time	8.25	hrs	Av. Wt. on Btm	2500	lbs
24 hr Footage	548	ft	Av. Press off Btm	1700	psi
Av. 24 hr Drilling ROP	66.4	ft/hr	Av. Wt. off Btm	32,000	lbs

OPERATIONAL DRILLS

Last BOP Stack Test	26-08-98	
Last Kick Drill		
SCR Depth	7440	ft
SCR	1	bpm
SCR Pressure	627	psi
Platform/ Fire Drill	28-08-98	
H2S Drill		

SURVEY DATA

MD	TVD	Incl	Azim
8191.0	6686.0	90.5	358.8
8221.0	6685.0	90.3	3.8
8251.0	6686.0	89.3	9.0
8282.0	6686.8	88.2	14.7
8312.0	6687.6	88.4	17.0
8406.0	6692.0	86.8	17.8
8468.0	6694.9	88.3	13.9
8557.0	6695.0	91.8	13.5
8653.0	6693.0	90.3	14.5

Critical Annular Velocities

Depth	OD	ID	Rate	An Vel
7254 ft	3.958	2.375	1.8 bpm	184
7771	3.5	2.375	1.8 bpm	280
Lst Csg	9 5/8 in.	47.0 ppf	7578 ft MD	HUD

Third Party Man Hours

Company	Man Hours	No.
Baker Hughes Inteq	72	6.0
Schlumberger W&T	48	4.0
	0	
Total	120	

COILLife

2 3/8"	0.190 HS-80
Depth	% Used
6870	14
7460	17
8714	8
Length	12425 ft

Screen Sizes

Top:	
Btm:	

Volumes

Active	380
Coil	46.7
Hole	123
Reserve	
Coil Disp	41.3

Rheology

MW	
FV	
PV	
YP	
Gels10/10	
600	
300	
200	
6	
3	
LGS	
Filtrate	
PH	

Oilfield Services Personnel

Day Shift		Night Shift	
John Smith	CTD Sup		
**********	Driller	Cees Bijleveld	Driller
**********	Op	Deryll Paliveda	Op
**********	Pump	Morgens Pedersen	Pump
**********	Helper	Jacob Jensen	Helper

Total OFS Pers: 0	Total Hrs 2388	Days:	199
Combined Parties Man Hours Worked			3900
Combined Parties Man Days Worked			325

COILED TUBING DRILLING DAILY REPORT

Report Nr: 23

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Oilfield Services District:	Location:	Report Date:	3-Sep-98
Operator:	Well No:	Well Type:	Gas Injector
CTD Rep.:		Company Rep.:	
Signature:		Signature:	

Start	Finish	Code	Operation	Distribution	Hrs
0:00	2:00	2	Drill 3.5" hole from 7955 ft to 8045 ft DWOB max 4.5 k lbs, norm 3/3.5 k lbs	1.Rig up/down	0:00
			Pump rate 2 bpm/1882 psi, annulus pressure 3150 psi	2.Drilling	8:15
2:00	2:45	13	Wiper trip to 7840 ft. Up weight 30k lbs. Hole good	3.Milling	0:00
2:45	5:00	2	Drill 3.5" hole from 8045 ft to 8315 ft. Lined up on well trajectory. Top of	4.Reaming	0:00
			Maastrichian 7861 ft.	5.Circ & Condition	0:00
5:00	11:00	6	POH to change motor angle. Circulating rate while POH 0.6 bpm/386 psi	6.Tripping	10:00
			Hole good. No circulation through the window.	7.Orienting	0:00
			Continue to circulate to surface 0.6 bpm/ 386 psi. Hole 185 psi on choke	8.Logging	0:00
			Stop circulating, close well in upper swab, close master and choke.	9.MWD / Surveying	0:00
11:00	13:00	27	Wind speed and direction make adverse working condition in tower.	10.Run Liner	0:00
			Assess situation. Wind speed 42 gusting 54 knots	11.Cementing	0:00
13:00	13:30	14	Lay out and change mud motor and bit from run 14	12.Perforating	0:00
13:30	14:00	14	Pick up mud motor and flow test .	13.Wiper Trip	0:45
14:00	15:00	14	Make up riser and pressure test 5000 psi and test check valves 1500 psi	14.BHA Handling	2:00
15:00	15:30	6	RIH (run 15) to 344 ft No circulation. WHP 80 psi, CT pressure 145 psi	15.Pressure Testing	0:00
15:30	16:30	30	BHI logging cabin electrical problem.	16.Well Control / Drill	0:00
16:30	20:00	6	Continue to RIH to 8315 ft .(Correlate with gamma marker (+20 ft))	17.Flow Check	0:00
			Down drag at 7557 ft 3k lbs, circulation rate 0.6 bpm/250 psi	18.BOP Test	0:00
20:00	0:00	2	Drill 3.5" hole from 8315 ft to 8503 ft	19.Stuck Pipe	0:00
			DWOB 1.5 - 2.0 k lbs, circ rate 1.8 bpm. Up weight 32k lbs	20.Loss circulation	0:00
				21.Fishing	0:00
				22.Maintenance	0:00
				23.Pipe Management	0:00
				24.CT Cleanout	0:00
				25.CT Treatment	0:00
				26.Safety Meeting	0:00
				27.WOW	2:00
				28.Wait on SLB.	0:00
				29.Wait on Orders	0:00
				30.Wait on Others	1:00
				31. Other	
				Total Hours	24:00:00

Start	Finish	Code	Operations to 06:00 hrs & next 24 hrs planning	Safety Information	
0:00	1:30	2	Drill from 8503 ft to 8626 ft.	Last Safety Meeting	28.08.98
01:30	02:30	13	Wiper trip to 8200 ft. Maximum overpull 15k lbs	Reported Incidents	11
02:30	03:30	2	Drill from 8626 ft to 8710 ft. Difficult to get weight to bit. Pull back. Pipe stuck	Accidents	1
03:30	05:00	19	Attempt to free stuck pipe . Max pull 65,000 lbs. Pipe freed	Days Since LTA	19
05:00	06:00	6	POH, tight hole from 8200 ft to 7880 ft, increase circ rate, decrease pulling speed	Total Project Days	23

remarks:

Weight on bit affects the overall rate of penetration that can be achieved. In order to optimize drilling performance, a steady weight on bit needs to be maintained. This is extremely difficult, as the weight indicator on a coiled tubing unit cannot accurately depict the actual weight that is being applied down hole. It has therefore become standard practice to monitor pump pressure and maintain a penetration rate based this pump pressure so that the motor never stalls. Stalling of the motor is indicated by an increase in pump pressure. As pump pressure increases, the rate of penetration is decreased, so that a constant torque is placed on the motor. This process could be automated; however, it would require the pump to have a dampener to eliminate pressure spikes created by pump noise.

Coiled tubing controls can be automated to perform scheduled tasks that are required on a regular basis, such as oiling the chains, performing a pull test, monitoring skate pressures, and numerous other small tasks.

Operating parameters, such as engine temperatures, oil pressure and hydraulic pressures, also need to be monitored. These parameters can be monitored by the system and compared to a preset operating range. If the parameter is out of range, an alarm sounds, causing a preset operation to take place based on the alarm setting.

Much of this type of automation has already been developed and is currently used in the CT Express and the CT SEAS coiled tubing units. The primary disadvantage of this type of automation is the cost of programming and future equipment support requirements.

Monitoring of secondary equipment is crucial if a clean and complete record of an operation is to be obtained. It is common for different pieces of oilfield equipment to be required for today's operations. Each piece of equipment monitors its own operation and produces a report. These reports are collected at the end of the drilling project and are summarized into one report. It might be beneficial to be able to monitor all the Schlumberger standard equipment that could possibly be used at the well site during drilling operations from the control cabin.

Whether the ability to monitor each piece of equipment would be beneficial needs to be evaluated on a piece-by-piece basis with respect to value, cost, and ease of integration.

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Chapter

9

Work table

This chapter lists the standard components and tools commonly found on rotary drilling rigs. It is the responsibility of the design team to determine whether these components are necessary or how they can be integrated based on the end design.

Components

a. Air hoist for raising tools while block is supporting a load
b. Makeup cat head if makeup tongs are used
c. Breakout cat head for breakout tongs
d. Rotary hose leading to drilling swivel of top drive
e. Slips and slip bowl
f. Profile for bit breaker in the work table
g. Controls for top drive and block
h. Place to stand pipe, BHA assemblies and lubricator
i. BOP and diverter controls if all personnel will be on the work floor while running casing

Required tools

a. Bit breaker
b. TIW valve
c. Slips
d. Drill collar clamps
e. Casing elevators
f. Drillpipe elevators
g. Crossover subs

h. Lifting subs
i. Chain tongs
j. Pipe dope
k. Standard end wrenches
l. Pliers
m. Pipe wrenches
n. Screw drivers
o. 5 lb and 10 lb sledge
p. Tape measure
q. Allen wrenches

Chapter

10

Rotary equipment

This chapter describes the differences between a top drive system and a power swivel. The rotary table is not addressed in any detail as it is not well suited to coiled tubing drilling unit operations.

A top drive is the obvious selection over a rotary table for coiled tubing drilling applications, for the following reasons. A rotary rig requires a taller derrick to handle the Kelly on top of the drillpipe when drilling begins; and the Kelly takes up considerable space on the work floor and requires both makeup and breakout tongs for making connections. A top drive system can torque drillpipe connections using only a backup tong.

Some Canadian drillers use rotary capabilities as a backup with coiled tubing drilling. These operators prefer rotary drilling for the simple reason that it has formed their experience and is the basis of their knowledge.

A top drive is used on a coiled tubing drilling unit to drill the conductor, and possibly the surface string in certain applications. Conductors are rotary drilled primarily because there is insufficient rat hole to make up the long drilling BHA required for coiled tubing drilling. It is also easier to initiate a straight hole with coiled tubing if there is sufficient hang weight to straighten out the coiled tubing.

A top drive might not be necessary for this project. A power swivel, which has fewer capabilities than a top drive system, might be sufficient. The advantage of the power swivel is that it is a much smaller, more compact and lighter piece of equipment than a top drive. A side-by-side comparison based on benefits and ease of installation is recommended once a preliminary concept has been established.

The differences between a power swivel and a top drive system are listed as follows.

Power swivel

- Hydraulically powered rotation
- Ability to support rotating pipe load
- Sealed swivel arrangement to convey drilling fluid to rotating joint

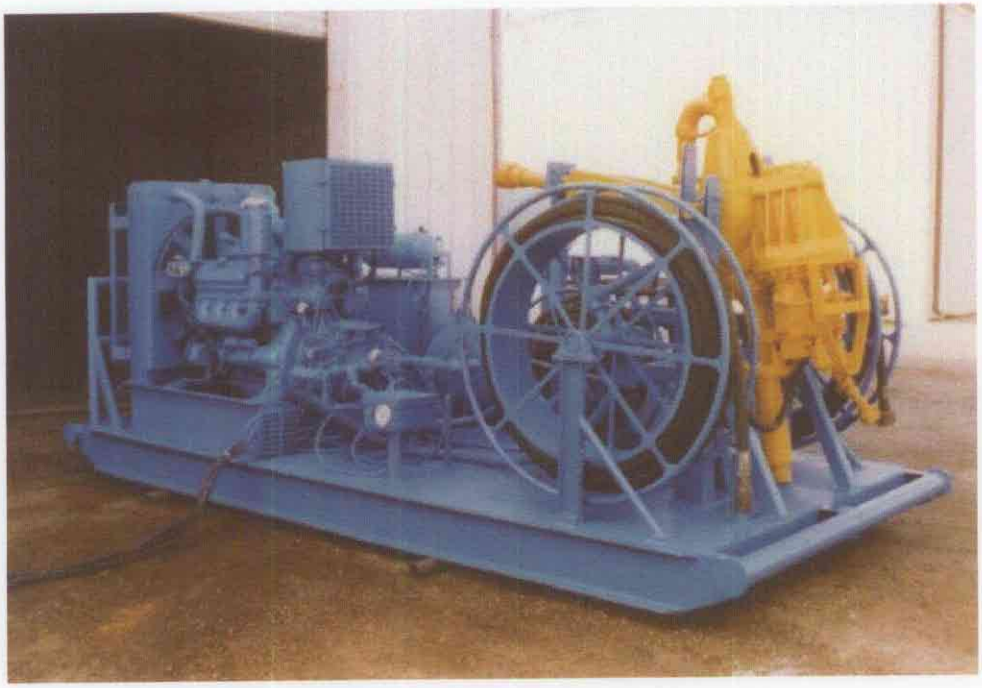
Top Drive

Includes all functionality of the power swivel (above) plus the following additional functions.

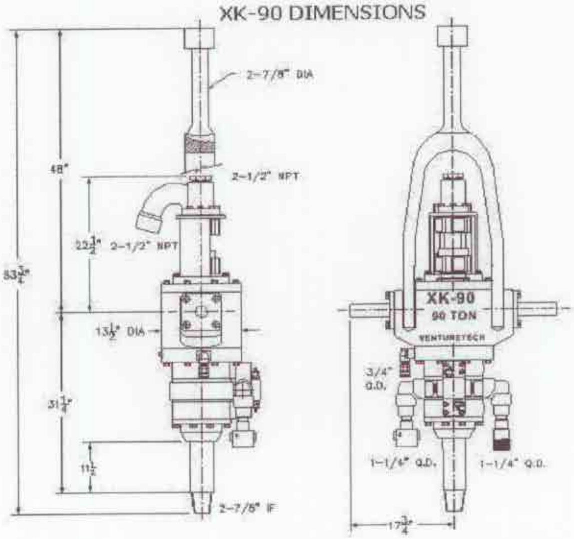
- Hydraulically manipulated elevators
- Ability to trip pipe with power swivel
- Ability to drill with doubles or triples
- Ability to make and break connections by remote control

Source: Venturetech Group

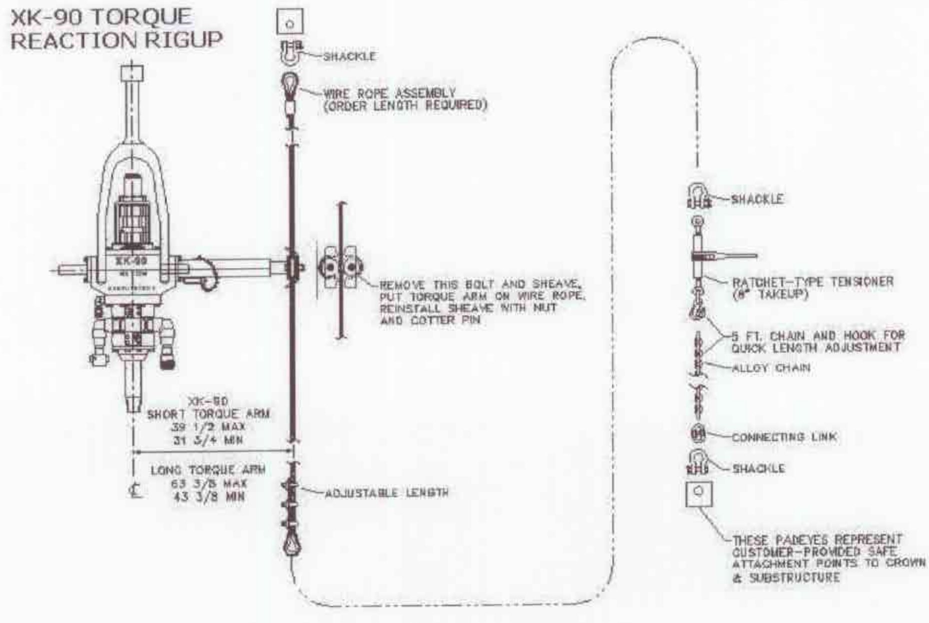
The following figures illustrate an example of a power swivel and its standard dimensions.



XK-90 DIMENSIONS



Source: Venture tech Group



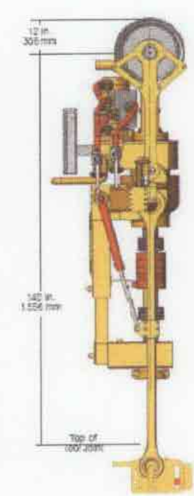
Source: Venture Tech Group

The following figures provide a side-by-side visual comparison between a top drive system and a power swivel.

Power Swivel

Source: Venture Tech Group

Top Drive



Source: Tesco

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